

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 September 30, 2004

Commission File Number 1-8754

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

TEXAS
(State of Incorporation)

74-2073055
(I.R.S. Employer Identification No.)

16825 Northchase Drive, Suite 400
Houston, Texas
(Address of principal executive offices)

77060
(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 and Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes No

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

Common Stock
(\$0.01 Par Value)
(Class of Stock)

28,030,317 Shares
(Outstanding at October 31, 2004)

SWIFT ENERGY COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2004
INDEX

PART I - FINANCIAL INFORMATION	PAGE
Item 1. Condensed Consolidated Financial Statements.	
Condensed Consolidated Balance Sheets - September 30, 2004 and December 31, 2003	3
Condensed Consolidated Statement of Income - For the Three month and Nine month periods ended September 30, 2004 and 2003	4
Condensed Consolidated Statements of Stockholders' Equity - For the Nine month period ended September 30, 2004 and year ended December 31, 2003	5
Condensed Consolidated Statements of Cash Flows - For the Nine month periods ended September 30, 2004 and 2003	6
Notes to Condensed Consolidated Financial Statements	7
Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.	19
Item 3. Quantitative and Qualitative Disclosures About Market Risk.	31
Item 4. Controls and Procedures.	33
PART II. OTHER INFORMATION	
Item 1. Legal Proceedings	34
Item 2. Unregistered Sales of Securities and Use of Proceeds	None
Item 3. Defaults Upon Senior Securities	None
Item 4. Submission of Matters to a Vote of Security Holders	None
Item 5. Other Information	34
Item 6. Exhibits	34
SIGNATURES	35

CONDENSED CONSOLIDATED BALANCE SHEETS
SWIFT ENERGY COMPANY

	September 30, 2004	December 31, 2003
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ 4,281,527	\$ 1,066,280
Accounts receivable -		
Oil and gas sales	29,388,512	26,082,650
Joint interest owners	1,493,098	1,350,707
Other current assets	6,922,297	5,610,420
Total Current Assets	42,085,434	34,110,057
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties being amortized	1,408,446,400	1,305,110,582
Unproved properties not being amortized	73,368,548	67,557,969
	1,481,814,948	1,372,668,551
Furniture, fixtures, and other equipment	11,603,507	10,602,786
	1,493,418,455	1,383,271,337
Less-Accumulated depreciation, depletion, and amortization	(625,468,058)	(567,464,334)
	867,950,397	815,807,003
Other Assets:		
Deferred income taxes	2,762,588	1,905,909
Debt issuance costs	9,404,282	8,015,575
	12,166,870	9,921,484
	\$ 922,202,701	\$ 859,838,544
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	\$ 21,104,321	\$ 26,247,477
Accrued capital costs	14,216,880	29,417,542
Accrued interest	11,053,499	8,748,656
Undistributed oil and gas revenues	6,423,277	4,939,667
Total Current Liabilities	52,797,977	69,353,342
Long-Term Debt	356,200,000	340,254,783
Deferred Income Taxes	59,682,338	43,498,682
Asset Retirement Obligation	8,680,547	9,340,473
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 share authorized, 28,467,891 and 28,011,109 shares issued, and 27,987,023 and 27,484,091 shares outstanding, respectively	284,679	280,111
Additional paid-in capital	339,812,135	334,865,204
Treasury stock held, at cost, 480,868 and 527,018 shares, respectively	(6,896,245)	(7,558,093)
Retained earnings	111,689,882	70,073,384
Other comprehensive loss, net of taxes	(48,612)	(269,342)
	444,841,839	397,391,264
	\$ 922,202,701	\$ 859,838,544

See accompanying notes to condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
SWIFT ENERGY COMPANY

	Three Months Ended		Nine Months Ended	
	09/30/04	09/30/03	09/30/04	09/30/03
Revenues:				
Oil and gas sales	\$ 74,653,106	\$ 52,087,321	\$ 212,431,665	\$ 157,846,870
Price-risk management and other, net	289,645	(534,799)	(1,089,449)	(2,076,826)
	74,942,751	51,552,522	211,342,216	155,770,044
Costs and Expenses:				
General and administrative, net	4,390,432	3,670,416	12,595,665	10,564,959
Depreciation, depletion and amortization	19,845,167	16,042,377	57,649,907	46,630,689
Accretion of asset retirement obligation	168,135	206,475	498,870	623,761
Lease operating costs	9,848,949	8,664,259	29,910,742	25,149,050
Severance and other taxes	7,077,994	5,066,208	20,251,822	14,243,481
Interest expense, net	7,317,002	6,749,419	21,361,566	20,107,188
Debt retirement cost	6,822,476	---	9,513,719	---
	55,470,155	40,399,154	151,782,291	117,319,128
Income Before Income Taxes and Cumulative Effect of Change in Accounting Principle				
	19,472,596	11,153,368	59,559,925	38,450,916
Provision for Income Taxes	5,341,879	4,090,743	17,943,427	13,681,928
Income Before Cumulative Effect of Change in Accounting Principle				
	14,130,717	7,062,625	41,616,498	24,768,988
Cumulative Effect of Change in Accounting Principle (net of taxes)				
	---	---	---	4,376,852
Net Income				
	\$ 14,130,717	\$ 7,062,625	\$ 41,616,498	\$ 20,392,136
Per share amounts				
Basic:				
Income Before Cumulative Effect of Change in Accounting Principle	\$ 0.51	\$ 0.26	\$ 1.50	\$ 0.91
Cumulative Effect of Change in Accounting Principle	---	---	---	(0.16)
Net Income	\$ 0.51	\$ 0.26	\$ 1.50	\$ 0.75
Diluted:				
Income Before Cumulative Effect of Change in Accounting Principle	\$ 0.50	\$ 0.26	\$ 1.47	\$ 0.90
Cumulative Effect of Change in Accounting Principle	---	---	---	(0.16)
Net Income	\$ 0.50	\$ 0.26	\$ 1.47	\$ 0.74
Weighted Average Shares Outstanding	27,948,095	27,424,195	27,747,789	27,326,169

See accompanying notes to condensed consolidated financial statements

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

SWIFT ENERGY COMPANY

	Common Stock (1)	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total
Balance, December 31, 2002	\$ 278,116	\$ 333,543,471	\$ (8,749,922)	\$ 40,179,572	\$ (178,053)	\$ 365,073,184
Stock issued for benefit plans (83,201 shares)	1	(408,178)	1,191,829	-	-	783,652
Stock options exercised (142,807 shares)	1,428	1,315,964	-	-	-	1,317,392
Employee stock purchase plan (56,574 shares)	566	413,947	-	-	-	414,513
Comprehensive income:						
Net income	-	-	-	29,893,812	-	29,893,812
Change in fair value of cash flow hedges, net of income tax ...	-	-	-	-	(91,289)	(91,289)
Total comprehensive income	<u> </u>	<u> </u>	<u> </u>	<u> </u>	<u> </u>	<u>29,802,523</u>
Balance, December 31, 2003	<u>\$ 280,111</u>	<u>\$ 334,865,204</u>	<u>\$ (7,558,093)</u>	<u>\$ 70,073,384</u>	<u>\$ (269,342)</u>	<u>\$ 397,391,264</u>
Stock issued for benefit plans (46,150 shares)	-	166,298	661,848	-	-	828,146
Stock options exercised (406,364 shares)	4,064	4,278,536	-	-	-	4,282,600
Employee stock purchase plan (50,418 shares)	504	502,097	-	-	-	502,601
Comprehensive income:						
Net income	-	-	-	41,616,498	-	41,616,498
Change in fair value of cash flow hedges, net of income tax	-	-	-	-	220,730	220,730
Total comprehensive income	<u> </u>	<u> </u>	<u> </u>	<u> </u>	<u> </u>	<u>41,837,228</u>
Balance, September 30, 2004.....	<u>\$ 284,679</u>	<u>\$ 339,812,135</u>	<u>\$ (6,896,245)</u>	<u>\$ 111,689,882</u>	<u>\$ (48,612)</u>	<u>\$ 444,841,839</u>

(1)\$0.01 par value

See accompanying notes to condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
SWIFT ENERGY COMPANY

	Period Ended September 30,	
	2004	2003
Cash Flows From Operating Activities:		
Net income	\$ 41,616,498	\$ 20,392,136
Adjustments to reconcile net income to net cash provided by operating activities -		
Cumulative effect of change in accounting principle	---	4,376,852
Depreciation, depletion, and amortization	57,649,907	46,630,689
Accretion of asset retirement obligation	498,870	623,761
Deferred income taxes	17,534,427	13,375,807
Debt retirement cost – cash and non-cash	9,513,719	---
Other	839,048	658,524
Change in assets and liabilities -		
Increase in accounts receivable	(5,940,575)	(3,895,748)
Increase in accounts payable and accrued liabilities	2,402,826	413,820
Increase in accrued interest	2,304,843	1,446,218
	126,419,563	84,022,059
Cash Flows From Investing Activities:		
Additions to property and equipment	(128,499,752)	(101,510,935)
Proceeds from the sale of property and equipment	1,411,554	3,839,714
Net cash distributed as operator of oil and gas properties	(3,910,392)	(989,176)
Net cash received as operator of partnerships and joint ventures	81,254	471,957
Other	(101,164)	(89,635)
	(131,018,500)	(98,278,075)
Cash Flows From Financing Activities:		
Proceeds from long-term debt	150,000,000	---
Payments of long-term debt	(125,000,000)	---
Net proceeds from (payments of) bank borrowings	(9,700,000)	11,900,000
Net proceeds from issuances of common stock	3,559,781	1,218,224
Payments of debt retirement costs	(6,712,062)	---
Payments of debt issuance costs	(4,333,535)	---
	7,814,184	13,118,224
Net Increase (Decrease) in Cash and Cash Equivalents	3,215,247	(1,137,792)
Cash and Cash Equivalents at Beginning of Period	1,066,280	3,816,107
Cash and Cash Equivalents at End of Period	\$ 4,281,527	\$ 2,678,315
<u>Supplemental disclosures of cash flows information:</u>		
Cash paid during period for interest, net of amounts capitalized	\$ 18,200,440	\$ 17,825,296
Cash paid during period for income taxes	\$ 409,000	\$ 306,121

See accompanying notes to condensed consolidated financial statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
SWIFT ENERGY COMPANY

(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. Certain reclassifications have been made to prior period financial information to conform to the current period presentation. The condensed consolidated financial statements should be read in conjunction with the audited financial statements and the notes thereto included in the latest Form 10-K and Annual Report.

(2) Summary Of Significant Accounting Policies

Oil and Gas Properties

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 nine months ended September 30, 2004 and 2003, such internal costs capitalized totaled \$9.6 million and \$9.3 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the nine months ended September 30, 2004 and 2003, capitalized interest on our unproved properties totaled \$4.7 million and \$5.2 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 capitalized asset retirement obligations, 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. Furniture, fixtures, and other equipment are depreciated by the straight-line method at rates based on the estimated useful lives of the property. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-(Continued)
SWIFT ENERGY COMPANY

Geological and geophysical (G&G) costs incurred on developed properties are recorded in Proved Property and subject to amortization. In exploration areas, G&G costs are capitalized in Unproved Property 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 asset retirement obligation liability is limited to the sum of the estimated future net revenues from proved properties, excluding cash outflows from asset retirement obligations including future 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 September 30, 2004 consisted of natural gas and crude oil price floors with strike prices lower than the period-end price and therefore had no effect on prices used in this calculation. This calculation is done on a country-by-country basis for those countries with proved reserves.

The calculation of the Ceiling Test and provision for depreciation, depletion, and amortization 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 estimate. 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 condensed consolidated financial statements include the accounts of Swift Energy Company and our 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 investments in oil and gas partnerships where we are the general partner 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 condensed consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the condensed consolidated financial statements.

Accounts Receivable

Included in the "Accounts receivable" balance, which totaled \$30.9 million and \$27.4 million at September 30, 2004 and December 31, 2003, respectively, on the accompanying condensed consolidated balance sheets, is approximately \$2.3 million of receivables related to hydrocarbon volumes produced during 2001 and 2002

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-(Continued)
SWIFT ENERGY COMPANY

that have been disputed since early 2003. Accordingly, we did not record a receivable with regard to those 2003 disputed volumes.

We continually assess the collectibility of accounts receivable, and based on our judgment, we establish a reserve when we believe a receivable may not be collected. At both September 30, 2004 and December 31, 2003, we had an allowance for doubtful accounts of \$0.5 million. These allowances for doubtful accounts have been deducted from the total "Accounts receivable" balances on the accompanying condensed consolidated balance sheets.

Inventory

We value inventories at the lower of cost or market value. Cost of crude oil inventory is determined using the weighted average method, 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 September 30, 2004	Balance at December 31, 2003
Materials, Supplies and Tubulars...	\$ 3,996,866	\$ 2,965,813
Crude Oil	1,045,013	238,228
Total	\$ 5,041,879	\$ 3,204,041

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from estimates. Significant estimates include proved reserve volumes, DD&A, and deferred income taxes.

Income Taxes

The effective tax rate for the first nine months of 2004 was lower than the statutory tax rates primarily due to reductions from the New Zealand statutory rate attributable to the currency effect on New Zealand deferred income taxes, along with reductions to the domestic tax rate due to changes in prior year tax estimates that are updated after we filed the prior year tax return. The tax laws in the jurisdictions we operate in are continuously changing and professional judgments regarding such laws can differ. Although the Internal Revenue Service regulations concerning the recently enacted American Jobs Creation Act of 2004 have not been issued, we do not believe this act will have a material impact in the near-term on our financial position or cash flow from operations.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-(Continued)
SWIFT ENERGY COMPANY

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 assume, as of the beginning of the period, exercise of stock options using the treasury stock method. Certain of our stock options that would potentially dilute Basic EPS were antidilutive for the three months and nine months ended September 30, 2004 and 2003 were excluded. The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS (before cumulative effect of change in accounting principle) for the three month and nine month periods ended September 30, 2004 and 2003:

	Three Months Ended September 30,					
	2004			2003		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income Before Cumulative Effect of Change in Accounting Principle and Share Amounts.....	\$14,130,717	27,948,095	\$.51	\$7,062,625	27,424,195	\$.26
Stock Options	---	555,861		---	259,246	
Diluted EPS:						
Net Income Before Cumulative Effect of Change in Accounting Principle and Assumed Share Conversions	\$14,130,717	28,503,956	\$.50	\$7,062,625	27,683,441	\$.26
	Nine Months Ended September 30,					
	2004			2003		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income Before Cumulative Effect of Change in Accounting Principle and Share Amounts	\$41,616,498	27,747,789	\$ 1.50	\$24,768,988	27,326,169	\$.91
Stock Options	---	502,251		---	147,158	
Diluted EPS:						
Net Income Before Cumulative Effect of Change in Accounting Principle and Assumed Share Conversions	\$41,161,498	28,250,040	\$ 1.47	\$24,768,988	27,473,327	\$.90

Options to purchase approximately 2.8 million shares of common stock, at an average exercise price of \$17.65 were outstanding at September 30, 2004, and options to purchase approximately 2.9 million shares of common stock, at an average price of \$16.61 were outstanding at September 30, 2003. Approximately 0.9 million and 1.3 million options to purchase shares were not included in the computation of Diluted EPS for the three month periods ended September 30, 2004 and 2003, respectively, and approximately 0.9 million and 1.6 million options to purchase shares were not included in the computation of Diluted EPS for the nine month periods ended September 30, 2004 and 2003, respectively, because the options were antidilutive, given that the option price was greater than the average closing market price of the common shares during those periods.

Other Comprehensive Loss

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 September 30, 2004, we recorded \$48,612, net of taxes of \$27,702, of derivative losses in “Other comprehensive loss” on the

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-(Continued)
SWIFT ENERGY COMPANY

accompanying balance sheet. The components of accumulated other comprehensive loss and related tax effects for the nine month period ended September 30, 2004 were as follows:

	<u>Gross Value</u>	<u>Tax Effect</u>	<u>Net of Tax Value</u>
Balance at December 31, 2003	\$ 420,847	\$ 151,505	\$ 269,342
Change in fair value of cash flow hedges	911,302	332,065	579,237
Effect of cash flow hedges settled during the period	<u>(1,255,835)</u>	<u>(455,868)</u>	<u>(799,967)</u>
Balance at September 30, 2004	<u>\$ 76,314</u>	<u>\$ 27,702</u>	<u>\$ 48,612</u>

For the nine month periods ended September 30, 2004 and 2003, total comprehensive income was \$41.8 million and \$20.5 million, respectively. For the three month periods ended September 30, 2004 and 2003, total comprehensive income was \$14.2 million and \$7.3 million, respectively.

Stock Based Compensation

We account for three stock-based compensation plans under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. No stock-based employee compensation cost is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of the grant; or in the case of the employee stock purchase plan, the purchase price is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year or a date during the year chosen by the participant. Had compensation expense for these plans been determined based on the fair value of the options consistent with SFAS No. 123, "Accounting for Stock-Based Compensation," our net income and earnings per share would have been adjusted to the following pro forma amounts:

		<u>Three Months Ended September 30,</u>	
		<u>2004</u>	<u>2003</u>
Net Income:	As Reported	\$14,130,717	\$7,062,625
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	<u>(1,059,331)</u>	<u>(1,024,734)</u>
	Pro Forma	\$13,071,386	\$6,037,891
Basic EPS:	As Reported	\$.51	\$.26
	Pro Forma	\$.47	\$.22
Diluted EPS:	As Reported	\$.50	\$.26
	Pro Forma	\$.46	\$.22

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-(Continued)
SWIFT ENERGY COMPANY

		Nine Months Ended September 30,	
		2004	2003
Net Income:	As Reported	\$41,616,498	\$20,392,136
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(3,170,157)	(3,048,052)
	Pro Forma	\$38,446,341	\$17,344,084
Basic EPS:	As Reported	\$1.50	\$.75
	Pro Forma	\$1.39	\$.63
Diluted EPS:	As Reported	\$1.47	\$.74
	Pro Forma	\$1.36	\$.63

Pro forma compensation cost reflected above may not be representative of the cost to be expected in future periods. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model.

Price-Risk Management Activities

Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Every derivative instrument (including certain derivative instruments embedded in other contracts) are recorded in the balance sheet as either an asset or a liability measured at its fair value. Hedge accounting for qualifying hedges 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 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 third quarters of 2004 and 2003, we recognized net losses of \$0.2 million and \$0.6 million, respectively, relating to our derivative activities. During the first nine months of 2004 and 2003, we recognized net losses of \$1.3 million and \$2.4 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 September 30, 2004, we had recorded \$48,612, net of taxes of \$27,702, of derivative losses in "Other comprehensive loss" 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 nine months of 2004 and 2003 were not material. We expect to reclassify all amounts currently held in "Other comprehensive loss" into the statement of income within the next six months when the forecasted sale of hedged production occurs.

As of September 30, 2004, we had in place natural gas price floors in effect for the October 2004 contract month through the March 2005 contract month, which cover a portion of our domestic natural gas production for October 2004 to March 2005. The natural gas price floors cover notional volumes of 950,000 Mmbtu with a weighted average floor price of \$5.63 per Mmbtu. Our natural gas hedges in place at September 30, 2004 are expected to cover approximately 10% to 15% of our domestic natural gas production from October 2004 to March 2005. As of September 30, 2004, we also had crude oil price floors in effect for the January 2005 contract month through the March 2005 contract month, which cover a portion of our domestic crude oil production for January 2005 through March 2005. The crude oil price floors cover notional volumes of 216,000 barrels with a weighted average floor price of \$37.00 per barrel. Our crude oil floors at September 30, 2004 are expected to cover approximately 15% to 20% of our domestic crude oil production from January 2005 to March 2005.

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 and crude oil production. Changes in

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-(Continued)
SWIFT ENERGY COMPANY

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 "Other comprehensive income (loss)." When the hedged transactions are recorded upon the actual sale of oil and natural gas, these gains or losses are reclassified from "Other comprehensive income (loss)" and recorded in "Price-risk management and other, net" on the condensed consolidated statement of income. The fair value of our derivatives are computed using the Black-Scholes option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments at September 30, 2004, was \$0.1 million and is recognized on the balance sheet in "Other current assets."

Asset Retirement Obligation

In June 2001, the Financial Accounting Standards Board 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. SFAS No. 143 was adopted by us effective January 1, 2003. Upon adoption of SFAS No. 143 effective January 1, 2003, we recorded an asset retirement obligation of \$8.9 million, an addition to oil and gas properties of \$2.0 million and a non-cash charge of \$4.4 million (net of \$2.5 million of deferred taxes), which is recorded as a Cumulative Effect of Change in Accounting Principle. The cumulative charge to earnings took into consideration the impact of adopting SFAS No. 143 on previous full-cost ceiling tests. SFAS No. 143 is silent with respect to whether prior period ceiling tests should be reflected in the implementation entry calculation; however, management believes that any impairment on the properties should be reflected in the historical periods. Had we not considered the impact of adopting SFAS No. 143 on previous full-cost ceiling tests, the charge recognized would have been reduced. Excluding the Cumulative Effect of Change in Accounting Principle, the adoption of SFAS No. 143 reduced our net income for the three months and nine months ended September 30, 2003 by approximately \$0.2 million and \$0.5 million, respectively, or less than \$0.01 per diluted share for the three months and \$0.02 per diluted share for the nine months period. The following is a roll-forward of our asset retirement obligation:

	2004	2003
Asset Retirement Obligation recorded as of January 1	\$ 10,137,473	\$ 8,934,320
Accretion expense for the nine months ended September 30	498,870	623,761
Liabilities incurred for new wells and facilities construction	315,404	546,350
Reductions due to sold, or plugged and abandoned wells	(234,769)	(332,327)
Increase due to currency exchange rate fluctuations	37,569	62,591
Asset Retirement Obligation as of September 30	\$ 10,754,547	\$ 9,834,695

At September 30, 2004 and December 31, 2003, approximately \$2.1 million and \$0.8 million, respectively, of our asset retirement obligation is classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying condensed consolidated balance sheets.

New Accounting Principles

In June 2001, the FASB issued SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Intangible Assets." We adopted these statements on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires that all business combinations initiated after June 30, 2001, be accounted for using the purchase method and that intangible assets be disaggregated and reported separately from goodwill. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and other indefinite lived intangible assets are not amortized but reviewed annually for

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-(Continued)
SWIFT ENERGY COMPANY

impairment.

An issue, EITF Issue 04-2, had arisen for companies engaged in oil and gas exploration and production regarding the application of SFAS No. 141 and SFAS No. 142 as they relate to mineral rights held under lease or other contractual arrangements, and as to whether costs associated with these rights should be classified as intangible assets on the balance sheet, apart from other capitalized oil and gas property costs, and to provide specific footnote disclosure. In March 2004, the Emerging Issues Task Force of the FASB reached a consensus that mineral rights are tangible assets. In April 2004, the FASB ratified the EITF's consensus by issuing FASB Staff Position (FSP) 141-1 and 142-1, which amend SFAS No. 141 and SFAS No. 142 to address the inconsistency between the EITF consensus on EITF Issue No. 04-02 and SFAS No. 141 and SFAS No. 142. The FSP is effective for reporting periods beginning after April 29, 2004 and defines mineral rights as tangible assets. In September 2004, the EITF issued FASB Staff Position (FSP) 142-2, in which the FASB staff further concluded that the costs for acquiring contractual mineral rights in oil and gas properties would continue to be recorded as tangible assets. These staff positions had no impact on our consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46 (Revised December 2003), Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51 Consolidated Financial Statements (the "Interpretation"). The Interpretation significantly changes whether entities included in its scope are consolidated by their sponsors, transferors, or investors. The Interpretation introduces a new consolidation model - the variable interest model; which determines control (and consolidation) based on potential variability in gains and losses of the entity being evaluated for consolidation. The Interpretation provides guidance for determining whether an entity lacks sufficient equity or its equity holders lack adequate decision-making ability. These variable interest entities ("VIEs") are covered by the Interpretation and are to be evaluated for consolidation based on their variable interests. These provisions applied immediately to variable interests in VIEs created after January 31, 2003, and to variable interests in special purpose entities for periods ending after December 15, 2003. The provisions apply for all other types of variable interests in VIEs for periods ending after March 15, 2004. We have no variable interests in VIEs, nor do we have variable interests in special purpose entities. The adoption of this interpretation had no impact on our financial position or results of operations.

In March 2004, the FASB issued an exposure draft that would amend SFAS No. 123 "Accounting for Stock Based Compensation" and SFAS No. 95 "Statement of Cash Flows." This exposure draft was issued to improve existing accounting rules and provide more complete, higher quality information for investors on employee stock compensation matters. This statement is effective for interim or annual periods beginning after June 15, 2005. The exposure draft covers a wide range of equity-based arrangements including stock options. Under the FASB's proposal, share-based payments to employees, including stock options, would be treated the same as other forms of compensation by recognizing the related cost in the income statement. The expense of the award would generally be measured at fair value at the grant date. Current accounting guidance allows that the expense relating to employee stock options to only be disclosed in the footnotes of the financial statements. We are evaluating the effects that will result from future adoption of this proposed statement.

In September 2004, the EITF discussed an issue dealing with how to evaluate whether a partnership should be consolidated by its general partner, EITF Issue 04-5. The issue deals with rights held by the limited partners and how this affects the consolidation of partnerships by the sole general partner in accordance with generally accepted accounting principles, absent the existence of these rights held by the limited partners. The EITF will discuss this issue in the future and we do not believe this staff position will have a material impact on our Consolidated Financial Statements.

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 106 (SAB 106). SAB 106 expresses the SEC staff's views regarding SFAS No. 143 and its impact on both the full-cost ceiling test and the calculation of depletion expense. In accordance with SAB 106, beginning in the fourth quarter of 2004, undiscounted abandonment costs for future wells, not recorded at the present time but needed to develop the proved reserves in existence at the present time, should be included in the unamortized cost of oil and as properties, net of related salvage value, for purposes of computing DD&A. The effect of

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-(Continued)
SWIFT ENERGY COMPANY

including undiscounted abandonment costs of future wells to the undiscounted cost of oil and gas properties will increase depletion expense in future periods, however, not materially at the present time.

(3) Long-Term Debt

Our long-term debt, including the current portion, as of September 30, 2004 and December 31, 2003, was as follows (in thousands):

	September 30, 2004		December 31, 2003
Bank Borrowings	6,200	\$	15,900
Senior Subordinated Notes due 2009 ...	---		124,355
Senior Notes due 2011	150,000		---
Senior Subordinated Notes due 2012 ...	200,000		200,000
Long-Term Debt	356,200	\$	340,255

The unamortized discount on the Senior Subordinated Notes due 2009 was \$0.6 million at December 31, 2003.

Bank Borrowings

At September 30, 2004, we had \$6.2 million in 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. At December 31, 2003, we had \$15.9 million in outstanding borrowings under our credit facility. The interest rate is either (a) the lead bank's prime rate (4.75% at September 30, 2004) 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 increased, renewed and extended 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.

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 working capital and EBITDAX ratios), and limitations on incurring other debt or repurchasing our Senior Subordinated Notes due 2011 or Senior 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 active New Zealand subsidiaries as collateral for this credit facility. The borrowing base is re-determined at least every six months and was reaffirmed by our bank group at \$250.0 million effective November 1, 2004. 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 borrowing base review is scheduled for May 2005.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-(Continued)
SWIFT ENERGY COMPANY

Senior Subordinated Notes Due 2009

These notes consisted of \$125.0 million of 10 1/4% Senior Subordinated Notes due August 2009, which were issued at 99.236% of the principal amount on August 4, 1999, and were scheduled to mature on August 1, 2009. These notes were unsecured senior subordinated obligations. Interest on these notes had been payable semi-annually on February 1 and August 1. In June 2004, we repurchased \$32.1 million of these notes pursuant to a tender offer. In the second quarter of 2004, we recorded a charge of \$2.7 million related to the repurchase of these notes, which is recorded in "Debt retirement costs" on the condensed consolidated statement of income. The costs were comprised of approximately \$1.8 million of premiums paid to repurchase the notes, \$0.6 million to write-off unamortized debt issuance costs, \$0.2 million to write-off unamortized debt discount and approximately \$0.1 million of other costs. In July 2004, we repurchased approximately \$0.5 million of these notes, and as of August 1, 2004, we redeemed the remaining \$92.5 million in outstanding notes. In the third quarter of 2004, we recorded a charge of \$6.8 million related to the repurchase of these notes, which is recorded in "Debt retirement costs" on the condensed consolidated statement of income. The costs were comprised of approximately \$4.8 million of premiums paid to repurchase the notes, \$1.6 million to write-off unamortized debt issuance costs and \$0.4 million to write-off unamortized debt discount.

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 the Senior Notes is payable semi-annually on January 15 and July 15, and commences on January 15, 2005. On or after July 15, 2008, we may redeem some or all of the Senior 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 Senior Notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.625% of the principal amount of the Senior 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 condensed consolidated balance sheets and will be amortized to interest expense over the life of the notes using the effective interest method. Upon certain changes in control of Swift Energy, each holder of Senior Notes will have the right to require us to repurchase all or any part of the Senior 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 Senior 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 due 2011.

Senior Subordinated Notes Due 2012

These notes consist of \$200.0 million of 9 3/8% Senior Subordinated Notes due 2012, which were issued on April 16, 2002 at 100% of the principal amount, 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 borrowings under our bank credit facility. Interest on these notes is payable semi-annually on May 1 and November 1. 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 may redeem 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 the 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 Senior Subordinated 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 Subordinated Notes due 2012.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-(Continued)
SWIFT ENERGY COMPANY

The aggregate maturities on our long-term debt are \$0 in 2004, 2005, 2006, 2007, \$6.2 million in 2008 and \$350.0 million thereafter, respectively.

(4) Foreign Activities

As of September 30, 2004, our gross capitalized oil and gas property costs in New Zealand totaled approximately \$231.6 million. Approximately \$197.3 million has been included in the proved properties portion of our oil and gas properties, while \$34.3 million is included as unproved properties. Our functional currency in New Zealand is the U.S. dollar.

(5) Segment Information

We have 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, general and administrative expenses, interest expense, net and debt retirement costs. Our reportable segments are managed separately based on their geographic locations. Financial information by operating segment is presented below:

	Three Months Ended September 30,					
	2004			2003		
	Domestic	New Zealand	Total	Domestic	New Zealand	Total
Oil and gas sales	\$ 63,497,169	\$ 11,155,937	\$ 74,653,106	\$ 39,974,435	\$ 12,112,886	\$ 52,087,321
Costs and Expenses:						
Depreciation, depletion and amortization ...	15,112,143	4,733,024	19,845,167	11,645,480	4,396,897	16,042,377
Accretion of asset retirement obligation	124,781	43,354	168,135	151,188	55,287	206,475
Lease operating costs	7,293,487	2,555,462	9,848,949	6,183,755	2,480,504	8,664,259
Severance and other taxes	6,310,555	767,439	7,077,994	4,076,456	989,752	5,066,208
Income from oil and gas operations	\$ 34,656,203	\$ 3,056,658	\$ 37,712,861	\$ 17,917,556	\$ 4,190,446	\$ 22,108,002
Price-risk management and other, net			289,645			(534,799)
General and administrative, net			4,390,432			3,670,416
Interest expense, net			7,317,002			6,749,419
Debt retirement cost			6,822,476			---
Income before income taxes and cumulative effect of change in accounting principle			\$ 19,472,596			\$ 11,153,368

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-(Continued)
SWIFT ENERGY COMPANY

	Nine Months Ended September 30,					
	2004			2003		
	Domestic	New Zealand	Total	Domestic	New Zealand	Total
Oil and gas sales	\$ 177,918,389	\$ 34,513,276	\$ 212,431,665	\$ 123,693,311	\$ 34,153,559	\$ 157,846,870
Costs and Expenses:						
Depreciation, depletion and amortization ...	44,533,330	13,116,577	57,649,907	32,508,198	14,122,491	46,630,689
Accretion of asset retirement obligation	375,028	123,842	498,870	448,711	175,050	623,761
Lease operating costs	22,147,817	7,762,925	29,910,742	18,131,045	7,018,005	25,149,050
Severance and other taxes	17,792,020	2,459,802	20,251,822	11,401,071	2,842,410	14,243,481
Income from oil and gas operations	\$ 93,070,194	\$ 11,050,130	\$ 104,120,324	\$ 61,204,286	\$ 9,995,603	\$ 71,199,889
Price-risk management and other, net			(1,089,449)			(2,076,826)
General and administrative, net			12,595,665			10,564,959
Interest expense, net			21,361,566			20,107,188
Debt retirement cost			9,513,719			---
Income before income taxes and cumulative effect of change in accounting principle			<u>\$ 59,559,925</u>			<u>\$ 38,450,916</u>
Property, plant and equipment, net	<u>\$ 680,540,113</u>	<u>\$ 187,410,284</u>	<u>\$ 867,950,397</u>	<u>\$ 616,251,046</u>	<u>\$ 173,419,123</u>	<u>\$ 789,670,169</u>

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

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. The following information contains forward-looking statements. For a discussion of limitations inherent in forward-looking statements, see "Forward-Looking Statements" on page 30 of this report.

Overview

For the first nine months of 2004, we had revenues of \$211.3 million and production of 42.5 Bcfe. Our revenues were bolstered by oil and gas prices remaining strong during this period and our domestic production for the first nine months of 2004 increasing by 23% to 30.8 Bcfe compared to the same period in 2003. We continued to focus our efforts and capital throughout the third quarter on infrastructure improvements, increased production and the development of longer life reserves in the Lake Washington and AWP Olmos areas. Although our production in Lake Washington was shut-in for brief periods due to hurricane-related weather in the third quarter of 2004, our net production in Lake Washington for the first nine months of 2004 has almost doubled as compared to the same period in 2003, and averaged approximately 9,800 net barrels of oil equivalent per day, compared to approximately 5,000 net barrels of oil equivalent per day in the same period in 2003. During 2004, capital expenditures were also used for development in our three other domestic core areas. New Zealand accounted for 11.7 Bcfe of production in the first nine months of 2004, a 21% decrease from production in the same period in 2003. Natural gas production in New Zealand declined primarily due to natural production declines in our TAWN properties. The TAWN gas contract has been renegotiated to lower the total contract quantity and deliverability rates, and we anticipate meeting these revised contracted volumes. There is no penalty if the fields are unable to produce these minimum contracted volumes. We are currently drilling a development well in the Tariki field to maximize production and deliverability from that field. New Zealand natural gas and natural gas liquids ("NGL") contracts are denominated in the New Zealand dollar, which has significantly strengthened during the last several years against the U.S. dollar.

Our production costs were up in the first nine months of 2004 predominately due to increased production in Lake Washington, higher severance taxes due to increased domestic revenues, and currency exchange rates in New Zealand. Our general and administrative expenses increased in the first nine months of 2004 primarily due an increase in costs related to our corporate governance activities and on going compliance efforts with the Sarbanes-Oxley Act, salaries and benefits, franchise tax expense, as well as higher costs in our New Zealand operations due to currency exchange rates. We are working to reduce our controllable production and general and administrative costs on a per unit produced basis for the remainder of 2004.

Our debt to PV-10 ratio decreased to 15% at September 30, 2004 compared to 22% at December 31, 2003, due to higher crude oil and natural gas prices, which have increased our PV-10 value. Our debt to capitalization ratio was 44% at September 30, 2004 compared to 46% at year-end 2003, as debt levels increased slightly in 2004 but were offset by the increase in retained earnings as a result of current year profit. In June 2004, we repurchased \$32.1 million of our 10 1/4% Senior Subordinated Notes due 2009 through a tender offer. We recorded a charge of \$2.7 million related to the tender offer, which is recorded in "Debt retirement costs" on the condensed consolidated statement of income. In July 2004, we repurchased \$0.5 million in Senior Subordinated Notes due 2009 at the close of the tender offer. On August 1, 2004, we redeemed the remaining \$92.5 million of these notes in accordance with our redemption rights under the indenture governing these notes. In the third quarter of 2004, we recorded approximately \$6.8 million of debt retirement costs related to the repurchase of these remaining notes. The redemption of our Senior Subordinated Notes due 2009 has lowered our effective interest rate.

We will continue to look for opportunities in the near term to improve our balance sheet and liquidity, but we expect our capital expenditures to continue to equal or modestly exceed our cash flow for the near term.

Our 2005 capital expenditure budget will be dependent upon operational performance and commodity pricing levels during the year, and we anticipate 2005 capital expenditures to approximate or slightly exceed our cash flow provided from operating activities during 2005.

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

Based on results for the first nine months of 2004 and on current operating conditions, we estimate that 2004 production levels will increase over 2003 levels by approximately 10%, which is lower than the previously estimated range of 11% to 15%. We continue to believe that commodity prices will remain strong for the remainder of 2004 and that we remain positioned for reserve growth over 2003 levels with our planned fourth quarter 2004 activities.

Results of Operations – Three Months Ended September 30, 2004 and 2003

Revenues. Our revenues in the third quarter of 2004 increased by 45% compared to revenues in the same period in 2003, due primarily to an increase in commodity prices and production from our Lake Washington area. Revenues from our oil and gas sales comprised substantially all of net revenues for the third quarter of 2004 and 2003. In the third quarter of 2004, oil production made up 46% of total production, natural gas made up 43% and NGL represented 11%. In the third quarter of 2003, natural gas production made up 49% of total production, oil production made up 40% and NGL represented 11%. The percentage of our total production from oil increased as Lake Washington production, which is almost entirely oil, increased over prior year levels. Although production in Lake Washington was shut-in for several days due to hurricane-related weather during the third quarter of 2004, continued development in this area has increased production significantly.

The following table provides additional information regarding the changes in the sources of our oil and gas sales and volumes from our four domestic core areas and two New Zealand core areas:

<u>Area</u>	<u>Three Months Ended September 30,</u>			
	<u>Oil and Gas Sales (In Millions)</u>		<u>Net Oil and Gas Sales Volumes (Bcfe)</u>	
	<u>2004</u>	<u>2003</u>	<u>2004</u>	<u>2003</u>
AWP Olmos	\$ 11.9	\$ 10.5	2.1	2.3
Brookeland	4.5	3.9	0.8	1.0
Lake Washington	37.1	16.6	5.5	3.5
Masters Creek	5.4	5.6	0.9	1.3
Other	4.6	3.4	0.9	0.6
Total Domestic	\$ 63.5	\$ 40.0	10.2	8.7
Rimu/Kauri	4.4	3.5	1.0	1.0
TAWN	6.8	8.6	2.7	3.9
Total New Zealand	\$ 11.2	\$ 12.1	3.7	4.9
Total	\$ 74.7	\$ 52.1	13.9	13.6

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

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

	<u>Net Sales Volume</u>				<u>Average Sales Price</u>		
	<u>Oil (MBbl)</u>	<u>NGL (MBbl)</u>	<u>Gas (Bcf)</u>	<u>Combined (Bcfe)</u>	<u>Oil (Bbl)</u>	<u>NGL (Bbl)</u>	<u>Gas (Mcf)</u>
<u>2004</u>							
Three Months Ended September 30:							
Domestic	1,008	151	3.2	10.2	\$41.60	\$26.44	\$5.47
New Zealand	68	100	2.8	3.7	\$47.75	\$18.63	\$2.21
Total	<u>1,076</u>	<u>251</u>	<u>6.0</u>	<u>13.9</u>	<u>\$41.99</u>	<u>\$23.33</u>	<u>\$3.97</u>
<u>2003</u>							
Three Months Ended September 30:							
Domestic	757	179	3.2	8.7	\$29.33	\$17.96	\$4.63
New Zealand	160	68	3.5	4.9	\$28.83	\$13.76	\$1.87
Total	<u>917</u>	<u>247</u>	<u>6.7</u>	<u>13.6</u>	<u>\$29.24</u>	<u>\$16.81</u>	<u>\$3.17</u>

Oil and gas sales in the third quarter of 2004 increased by 43%, or \$22.6 million, from the level of those revenues for the same period in 2003. The increase in production volumes during the third quarter of 2004 was primarily from our Lake Washington area.

In the third quarter of 2004, our \$22.6 million increase in oil, NGL, and gas sales resulted from:

- Price variances that had a \$20.1 million favorable impact on sales, of which \$13.7 million was attributable to the 44% increase in average oil prices received, \$4.7 million was attributable to the 25% increase in average gas prices received, and \$1.6 million was attributable to the 39% increase in average NGL prices received; and
- Volume variances that had a \$2.5 million favorable impact on sales, with \$4.6 million of increases coming from the 159,000 Bbl increase in oil sales volumes, \$0.1 million of increases due to the 3,000 Bbl increase in NGL sales volumes, partially offset by a \$2.2 million decrease attributable to the 0.7 Bcf decrease in gas sales volumes.

Costs and Expenses. Our total expenses in the third quarter of 2004 increased \$15.1 million, or 37%, compared to expenses in the same period in 2003. The majority of the increase was due to debt retirement costs of \$6.8 million related to the repurchase of a portion of our Senior Subordinated Notes due 2009, an increase of \$3.8 million in depreciation, depletion and amortization, a \$2.0 million increase in severance taxes, and a \$1.2 million increase in lease operating costs.

Our third quarter of 2004 general and administrative expenses, net, increased \$0.7 million, or 20%, from the level of such expenses in the same 2003 period. This increase was due primarily to an increase in salaries and benefits, increased costs related to our on going compliance efforts with the Sarbanes-Oxley Act, as well as higher costs in our New Zealand operations due to the increased currency exchange rate of the New Zealand dollar as compared to the U.S. dollar. Our general and administrative expenses per Mcfe produced were \$0.32 per Mcfe in the third quarter of 2004 and \$0.27 in the 2003 period. The portion of supervision fees recorded as a reduction of general and administrative expenses were \$1.6 million for the third quarter of 2004 and \$0.8 million for the same period in 2003.

Depreciation, depletion, and amortization of our oil and gas properties, or DD&A, increased \$3.8 million, or 24%, in the third quarter of 2004 from 2003 levels. Domestically, DD&A increased \$3.5 million in the 2004 period, mainly due to higher production in the period, and the DD&A rate per Mcfe of production increased to

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

\$1.49 from \$1.33 in the comparable 2003 period mainly due to increases in future development costs and oil and gas property additions, which increased our full-cost pool balance. In New Zealand, DD&A increased \$0.3 million in the 2004 period as the DD&A rate per Mcfe of production increased to \$1.26 from \$0.90 in the 2003 period mainly due to increases in future development costs and oil and gas property additions, which increased our full-cost pool balance in New Zealand. Our overall DD&A rate per Mcfe of production was \$1.43 in the third quarter of 2004 and \$1.18 in the comparable 2003 period.

We recorded \$0.2 million of accretion on our asset retirement obligation in both the third quarter of 2004 and 2003.

Our lease operating costs per Mcfe produced were \$0.71 in the third quarter of 2004 and \$0.64 in the same period of 2003. There were no supervision fees recorded as a reduction to production costs for the third quarter of 2004 and \$0.5 million for the same 2003 period. Our lease operating costs in the third quarter of 2004 increased \$1.2 million, or 14%, over the level of such expenses in the comparable 2003 period. Approximately \$1.1 million of the increase in lease operating costs during the third quarter of 2004 was related to our domestic operations, which increased due to higher production and facility repairs in our Lake Washington area in that period and the reduction to 2003 expense of \$0.5 million from supervision fees. Despite a decrease in production in New Zealand, production costs increased by \$0.1 million in the third quarter of 2004 primarily due to the continued development of our Kauri field and the increased currency exchange rate of the New Zealand dollar as compared to the U.S. dollar.

Severance and other taxes in the third quarter of 2004 increased \$2.0 million, or 40%, over the level of such expenses in the comparable 2003 period. The increase is mainly due to higher commodity prices and increased Lake Washington production in the third quarter of 2004. Severance and other taxes, as a percentage of oil and gas sales, were approximately 9.5% and 9.7% in the third quarters of 2004 and 2003, respectively.

Interest expense on our Senior Subordinated Notes due 2012, including amortization of debt issuance costs, totaled \$4.8 million in both the third quarter of 2004 and 2003. Interest expense on our Senior Subordinated Notes due 2009 which were repurchased in the second and third quarters of 2004, including amortization of debt issuance costs, totaled \$0.8 million in the third quarter of 2004 and \$3.3 million in 2003. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled \$0.3 million in both the third quarter of 2004 and 2003. Interest expense on our Senior Notes due 2011, issued in June 2004, was \$3.0 million in the third quarter of 2004. The total interest cost in the third quarter of 2004 was \$8.9 million, of which \$1.6 million was capitalized. The total interest cost in the third quarter of 2003 was \$8.4 million, of which \$1.7 million was capitalized.

In the third quarter of 2004, we incurred \$6.8 of debt retirement costs related to the redemption of the remaining portion of our Senior Subordinated Notes due 2009. The costs were comprised of approximately \$4.8 million of premiums paid to redeem the notes, \$1.6 million to write-off unamortized debt issuance costs and \$0.4 million to write-off unamortized debt discount.

The overall effective tax rate was 27.4% and 36.7% for the third quarters of 2004 and 2003, respectively. The effective tax rate for the third quarter of 2004 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, along with reductions to the domestic statutory tax rate due to changes from prior year tax estimates that are updated after we file the prior year's tax return and the adjustment of a domestic tax contingency.

Net Income. Our net income in the third quarter of 2004 of \$14.1 million was 100% higher, and Basic EPS of \$0.51 was 96% higher, than our third quarter of 2003 net income of \$7.1 million and Basic EPS of \$0.26. Our Diluted EPS in the third quarter of 2004 of \$0.50 was 94% higher than our 2003 Diluted EPS of \$0.26. These amounts increased in the 2004 period as oil and gas revenues increased due to higher commodity prices and increased domestic production.

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

Results of Operations – Nine Months Ended September 30, 2004 and 2003

Revenues. Our revenues in the first nine months of 2004 increased by 36% compared to revenues in the same period in 2003, due primarily to increases in oil prices and production from our Lake Washington and AWP areas domestically and our Rimu/Kauri area in New Zealand. Substantially all of our net revenues for the first nine months of 2004 and 2003 were from oil and gas sales. In the first nine months of 2004, oil production made up 47% of total production, natural gas made up 41% and NGL represented 12%. In the first nine months of 2003, natural gas production made up 54% of total production, oil production made up 37% and NGL represented 9%.

The following table provides additional information regarding the changes in the sources of our oil and gas sales and volumes from our four domestic core areas and two New Zealand core areas:

<u>Area</u>	<u>Oil and Gas Sales (In Millions)</u>		<u>Net Oil and Gas Sales Volumes (Bcfe)</u>	
	<u>2004</u>	<u>2003</u>	<u>2004</u>	<u>2003</u>
	AWP Olmos	\$ 36.2	\$ 34.6	6.9
Brookeland	13.8	12.3	2.7	2.9
Lake Washington	98.8	40.4	16.1	8.3
Masters Creek	16.0	21.3	2.9	4.6
Other	13.1	15.0	2.2	2.8
Total Domestic	<u>\$177.9</u>	<u>\$123.6</u>	<u>30.8</u>	<u>25.0</u>
Rimu/Kauri	13.8	6.8	3.2	2.0
TAWN	20.7	27.4	8.5	12.8
Total New Zealand	<u>\$ 34.5</u>	<u>\$ 34.2</u>	<u>11.7</u>	<u>14.8</u>
Total	<u>\$212.4</u>	<u>\$157.8</u>	<u>42.5</u>	<u>39.8</u>

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

	<u>Net Sales Volume</u>				<u>Average Sales Price</u>		
	<u>Oil (MBbl)</u>	<u>NGL (MBbl)</u>	<u>Gas (Bcf)</u>	<u>Combined (Bcfe)</u>	<u>Oil (Bbl)</u>	<u>NGL (Bbl)</u>	<u>Gas (Mcf)</u>
<u>2004</u>							
Nine Months Ended September 30:							
Domestic	3,047	540	9.3	30.8	\$37.58	\$23.29	\$5.48
New Zealand	296	257	8.3	11.7	\$39.26	\$17.62	\$2.20
Total	<u>3,343</u>	<u>797</u>	<u>17.6</u>	<u>42.5</u>	<u>\$37.72</u>	<u>\$21.46</u>	<u>\$3.93</u>
<u>2003</u>							
Nine Months Ended September 30:							
Domestic	2,010	419	10.4	25.0	\$29.96	\$20.18	\$5.30
New Zealand	418	213	11.0	14.8	\$29.03	\$13.33	\$1.74
Total	<u>2,428</u>	<u>632</u>	<u>21.4</u>	<u>39.8</u>	<u>\$29.80</u>	<u>\$17.87</u>	<u>\$3.46</u>

Oil and gas sales in the first nine months of 2004 increased by 35%, or \$54.6 million, from the level of those revenues for the same period in 2003. The increase in production volumes during the first nine months of 2004 was primarily from our Lake Washington and AWP Olmos areas domestically, and the Rimu/Kauri area in New Zealand.

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

In the first nine months of 2004, our \$54.6 million increase in oil, NGL, and gas sales resulted from:

- Price variances that had a \$37.5 million favorable impact on sales, of which \$26.5 million was attributable to the 27% increase in average oil prices received, \$8.2 million was attributable to the 13% increase in average gas prices received and \$2.8 million was attributable to the 20% increase in average NGL prices received; and
- Volume variances that had a \$17.1 million favorable impact on sales, with \$27.2 million of increases coming from the 914,000 Bbl increase in oil sales volumes, \$3.0 million of increases due to the 165,000 Bbl increase in NGL sales volumes, partially offset by \$13.1 million in decreases attributable to the 3.8 Bcf decrease in gas sales volumes.

Costs and Expenses. Our total expenses in the first nine months of 2004 increased \$34.5 million, or 29%, compared to expenses in the same period in 2003. The majority of the increase was due to an \$11.0 million increase in depreciation, depletion and amortization, \$9.5 million of debt retirement costs related to the repurchase of our Senior Subordinated Notes due 2009, a \$6.0 million increase in severance taxes, and a \$4.8 million increase in lease operating costs.

As discussed in Note 1 to the Condensed Consolidated Financial Statements, we adopted SFAS No. 143 on January 1, 2003. Our adoption of SFAS No. 143 resulted in a one-time net of taxes charge of \$4.4 million, which is recorded as a "Cumulative Effect of Change in Accounting Principle" in the 2003 condensed consolidated statement of income.

Our first nine months of 2004 general and administrative expenses, net, increased \$2.0 million, or 19%, from the level of such expenses in the same 2003 period. This increase is due primarily to increased costs related to our on going compliance efforts with the Sarbanes-Oxley Act, an increase in salaries and benefits, as well as higher costs in our New Zealand operations due to the increased currency exchange rate of the New Zealand dollar as compared to the U.S. dollar. Our general and administrative expenses per Mcfe produced were \$0.30 per Mcfe in the first nine months of 2004 and \$0.27 in the same 2003 period. The portion of supervision fees recorded as a reduction of general and administrative expenses was \$4.0 million for the first nine months of 2004 and \$2.2 million for the same 2003 period.

Depreciation, depletion, and amortization of our oil and gas properties, or DD&A, increased \$11.0 million, or 24%, in the first nine months of 2004 from 2003 levels for the same period. Domestically, DD&A increased \$12.0 million in the first nine months of 2004, mainly due to higher production in the period, and the DD&A rate per Mcfe of production increased to \$1.45 from \$1.30 in the comparable 2003 period mainly due to increases in future development costs and oil and gas property additions, which increased our full-cost pool balance. In New Zealand, DD&A decreased by \$1.0 million in the 2004 period due to decreased production in the period even though the DD&A per Mcfe of production increased to \$1.13 from \$0.95 mainly due to increases in future development costs and oil and gas property additions, which increased our full-cost pool balance in New Zealand. Our overall DD&A rate per Mcfe of production was \$1.36 in the first nine months of 2004 and \$1.17 in the comparable 2003 period.

We recorded \$0.5 million of accretion on our asset retirement obligation in the first nine months of 2004 and \$0.6 million in the comparable 2003 period.

Our lease operating costs per Mcfe produced were \$0.70 in the first nine months of 2004 and \$0.63 in the same period of 2003. There were no supervision fees recorded as a reduction to production costs for the first nine months of 2004 and \$1.5 million for the same 2003 period. Our lease operating costs in the first nine months of 2004 increased \$4.8 million, or 19%, over the level of such expenses in the comparable 2003 period. Approximately \$4.0 million of the increase in lease operating costs during the first nine months of 2004 was related to our domestic operations, which increased due to higher production from our Lake Washington and AWP Olmos areas in that period and the reduction of 2003 expense of \$1.5 million from supervision fees. Despite a decrease in production in New Zealand, production costs increased by \$0.8 million in the first nine months of 2004 primarily due to the continued development of our Kauri field and the increased currency

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

exchange rate of the New Zealand dollar as compared to the U.S. dollar.

Severance and other taxes in the first nine months of 2004 increased \$6.0 million, or 42%, over the level of such expenses in the comparable 2003 period. The increase was due primarily to higher commodity prices and increased Lake Washington, AWP Olmos, and Rimu/Kauri production. Severance taxes on oil in Louisiana are 12.5% of oil sales, therefore as our percentage of oil production, which comes from Lake Washington increases, the overall percentage of severance costs to sales will increase. Severance and other taxes, as a percentage of oil and gas sales, were approximately 9.5% and 9.0% in the first nine months of 2004 and 2003, respectively.

Interest expense on our Senior Subordinated Notes due 2012, including amortization of debt issuance costs, totaled \$14.4 million in the first nine months of 2004 and \$14.3 million in the 2003 period. Interest expense on our Senior Subordinated Notes due 2009 which were repurchased in the second and third quarters of 2004, including amortization of debt issuance costs, totaled \$7.4 million in the first nine months of 2004 and \$9.9 million in the 2003 period. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled \$1.1 million in the first nine months of both 2004 and 2003. Interest expense on our Senior Notes due 2011, issued in June 2004, was \$3.2 million in the first nine months of 2004. The total interest cost in the first nine months of 2004 was \$26.1 million, of which \$4.7 million was capitalized. The total interest cost in the first nine months of 2003 was \$25.3 million, of which \$5.2 million was capitalized.

In the first nine months of 2004, we incurred \$9.5 million of debt retirement costs related to the repurchase and redemption of our Senior Subordinated Notes due 2009. The costs were comprised of approximately \$6.5 million of premiums paid to repurchase the notes, \$2.2 million to write-off unamortized debt issuance costs, \$0.6 million to write-off unamortized debt discount and approximately \$0.2 million of other costs.

The overall effective tax rate was 30.1% and 35.6% for the first nine months of 2004 and 2003, respectively. The effective tax rate for the first nine months of 2004 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, along with reductions to the domestic statutory tax rate due to changes from prior year tax estimates that are updated after we file the prior year's tax return.

Net Income. Our net income in the first nine months of 2004 of \$41.6 million was 104% higher, and Basic EPS of \$1.50 was 101% higher, than our first nine months of 2003 net income of \$20.4 million and Basic EPS of \$0.75. Our Diluted EPS in the first nine months of 2004 of \$1.47 was 98% higher than our 2003 Diluted EPS of \$0.74. These amounts increased in the 2004 period as oil and gas revenues increased due to higher commodity prices, increased domestic production, and the effect of the cumulative effect of change in accounting principle recognized in the first nine months of 2003, offset somewhat by the charge for debt retirement costs in the 2004 period.

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

Contractual Commitments and Obligations

Our contractual commitments for the remainder of 2004 and the next five years and thereafter as of September 30, 2004 are as follows:

	Remainder of 2004	2005	2006	2007	2008	2009	Thereafter	Total
	(In thousands)							
Non-cancelable operating lease (1).....	\$ 536	\$2,430	\$2,484	\$2,482	\$2,450	\$2,339	\$ 13,025	\$ 25,746
Asset Retirement Obligation (2)	943	515	515	515	515	515	7,237	10,755
Drilling Rig and Seismic	7,184	---	---	---	---	---	---	7,184
Senior Notes due 2011 (3)	---	---	---	---	---	---	150,000	150,000
Senior Subordinated Notes due 2012 (3)	---	---	---	---	---	---	200,000	200,000
Credit Facility (4)	---	---	---	---	6,200	---	---	6,200
Total	\$8,663	\$2,945	\$2,999	\$2,997	\$9,165	\$2,854	\$370,262	\$399,885

(1) Our office lease in Houston, Texas extends until 2015.

(2) Amounts shown by year are the fair values at September 30, 2004.

(3) These amounts do not include the interest obligation, which is paid semi-annually.

(4) The credit facility expires in October 2008 and these amounts exclude a \$0.8 million standby letter of credit outstanding under this facility.

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 increased significantly in the first nine months of 2004 when compared to longer-term historical prices, and has recently hit record highs. Factors such as worldwide supply disruptions, worldwide economic conditions, fluctuating currency exchange rates, and actions taken by OPEC can cause wide fluctuations in the price of oil. Domestic natural gas prices continue to remain high when compared to longer-term historical prices. North American weather conditions, the industrial and consumer demand for natural gas, storage levels of natural gas, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of domestic natural gas. Such factors are beyond our control.

Income Tax Regulations

The tax laws in the jurisdictions we operate in are continuously changing and professional judgments regarding such tax laws can differ. Although the Internal Revenue Service regulations concerning the recently enacted American Jobs Creation Act of 2004 have not been issued, we do not believe this act will have a material impact on our financial position or cash flow from operations in the near-term.

Liquidity and Capital Resources

During the first nine months of 2004, we largely relied upon our net cash provided by operating activities of \$126.4 million and net proceeds from the offering of our Senior Notes due 2011 of \$150.0 million to fund capital expenditures of \$128.5 million and repurchase \$125.0 million of our Senior Subordinated Notes due 2009. During the first nine months of 2003, we relied upon our net cash provided by operating activities of

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

\$84.0 million and proceeds from borrowings under our bank credit facility of \$11.9 million to fund capital expenditures of \$101.5 million.

Net Cash Provided by Operating Activities. For the first nine months of 2004, net cash provided by operating activities was \$126.4 million, representing a 50% increase as compared to \$84.0 million generated during the first nine months of 2003. The \$42.4 million increase was primarily due to an increase of \$54.6 million in oil and gas sales for the 2004 period, attributable to higher commodity prices and increased domestic production, offset in part by lease operating cost increases due to higher domestic production, severance taxes due to higher commodity prices. Net cash provided by operating activities is \$6.7 million higher than announced in our earnings release on November 4, 2004 due to reclassifying the cash portion of debt retirement cost as a financing activity rather than an operating activity.

Accounts Receivable. Included in the "Accounts receivable" balance, which totaled \$30.9 million and \$27.4 million at September 30, 2004 and December 31, 2003, respectively, on the accompanying balance sheets, is approximately \$2.3 million of receivables related to hydrocarbon volumes produced from 2001 and 2002 that have been disputed since early 2003. Accordingly, we did not record a receivable with regard to those 2003 disputed volumes.

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 September 30, 2004 and December 31, 2003, we had an allowance for doubtful accounts of \$0.5 million. These allowances for doubtful accounts have been deducted from the total "Accounts receivable" balances on the accompanying condensed consolidated balance sheets.

Bank Credit Facility. We had \$6.2 million in borrowings under our bank credit facility at September 30, 2004, and \$15.9 million in outstanding borrowings at December 31, 2003. Our bank credit facility at September 30, 2004 consisted of a \$400.0 million revolving line of credit with a \$250.0 million borrowing base. The borrowing base is re-determined at least every six months and was reaffirmed by our bank group at \$250.0 million, effective November 1, 2004. In June 2004, we renewed this credit facility, increasing the facility amount to \$400.0 million from \$300.0 million and extending its expiration to October 1, 2008 from October 1, 2005. We maintained the commitment amount at \$150.0 million, which amount was set at our request effective May 9, 2003. 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, among other restrictions that changed somewhat as the facility was renewed and extended, requirements to maintain certain minimum financial ratios (principally pertaining to working capital and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of this agreement.

Repurchase of Senior Subordinated Notes due 2009. In June 2004, we repurchased \$32.1 million of our Senior Subordinated Notes due 2009 pursuant to a tender offer, and recorded debt retirement costs of \$2.7 million related to this repurchase. In July 2004, we repurchased approximately \$0.5 million of these notes, and as of August 1, 2004, we redeemed the remaining \$92.5 million of these notes. We have recorded \$6.8 million in the third quarter of 2004 for a total of \$9.5 million in debt retirement costs related to the total repurchase of these notes.

Debt Maturities. Our credit facility extends until October 1, 2008. Our \$150.0 million Senior Notes mature July 15, 2011, and our \$200.0 million Senior Notes mature May 1, 2012.

Working Capital. Our working capital improved from a deficit of \$35.2 million at December 31, 2003, to a deficit of \$10.7 million at September 30, 2004. The improvement was primarily due to an increase in accounts receivable due to higher sales prices and accrued volumes at September 30, 2004, along with a reduction in our accrued capital costs in the 2004 period due decreased capital activity when compared to year-end 2003.

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

Capital Expenditures. During the first nine months of 2004, we used \$128.5 million to fund capital expenditures for property, plant, and equipment. These capital expenditures included:

Domestic activities of \$102.7 million as follows:

- \$77.8 million for drilling and developmental activity costs;
- \$11.4 million of seismic costs, mainly in the Lake Washington area;
- \$10.8 million on prospect costs, principally prospect leasehold and geological costs of unproved prospects;
- \$1.7 million relating to costs directly associated with evaluating potential producing property acquisitions; and
- \$1.0 million primarily for computer equipment, software, furniture, and fixtures.

New Zealand activities of \$25.8 million as follows:

- \$20.6 million for drilling and developmental activity costs;
- \$5.0 million on prospect costs and geological costs of unproved prospects;
- \$0.2 million for furniture and fixtures.

We have spent considerable time and capital in 2003 and the first nine months of 2004, on significant facility capacity upgrades in the Lake Washington area to increase facility capacity to approximately 20,000 barrels per day for crude oil, up from 9,000 barrels per day capacity in the first quarter of 2003. We have upgraded three production platforms, added new compression for the gas lift system, and installed a new oil delivery system and permanent barge loading facility. We also began a seismic acquisition and interpretation program in our Lake Washington area that should continue through 2005. We are also continuing to work on and plan for further increases in facility capacity in the Lake Washington area.

We drilled or participated in drilling 37 domestic development wells and four domestic exploratory wells in the first nine months of 2004. Twenty of the development wells and one exploratory well were in the Lake Washington area. Thirteen of the development wells were in the AWP Olmos area. One domestic exploratory well and 31 of the domestic development wells were completed. In New Zealand, the Kauri-E3, E4, E5 and E6 wells were completed, five development Manutahi wells were drilled and completed, and one exploratory Manutahi well was unsuccessful. The Tariki D1 development well is currently drilling in the TAWN area.

For the last quarter of 2004, we expect to make capital expenditures of approximately \$40 to \$50 million. Our current estimated total capital expenditures for 2004 are approximately \$170.0 to \$180.0 million, excluding acquisition costs and net of approximately \$3.0 million to \$11.0 million in non-core property dispositions. Capital expenditures for 2003 were \$144.5 million.

Capital expenditure for 2005 will be dependent upon operational performance and commodity pricing levels during the year, and we anticipate these expenditures to approximate our cash flow from operating activities.

We believe that the anticipated internally generated cash flows for 2004, together with bank borrowings under our bank credit facility, will be sufficient to finance the costs associated with our currently budgeted 2004 capital expenditures. If producing property acquisitions become attractive during the fourth quarter of 2004, we will explore the use of debt and/or equity offerings to fund such activity.

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

During the last quarter of 2004, we anticipate drilling or participating in the drilling of up to an additional eight to twelve wells in the Lake Washington area, an additional 2 wells in the AWP Olmos area, and several additional wells, with varying working interest percentages, mainly in South Texas. In addition, we plan on drilling one Kauri well in New Zealand.

Our 2004 capital expenditures continue to be focused on developing and producing long-lived reserves in our Lake Washington, AWP Olmos, and Rimu/Kauri area. We expect our 2004 total production to increase over 2003 levels, primarily from the Lake Washington, AWP Olmos, and Rimu/Kauri areas. We expect production in our other core areas to decrease as limited new drilling is currently budgeted to offset the natural production decline of these properties.

New Accounting Principles

In June 2001, the FASB issued SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Intangible Assets." We adopted these statements on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires that all business combinations initiated after June 30, 2001, be accounted for using the purchase method and that intangible assets be disaggregated and reported separately from goodwill. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and other indefinite lived intangible assets are not amortized but reviewed annually for impairment.

An issue, EITF Issue 04-2, had arisen for companies engaged in oil and gas exploration and production regarding the application of SFAS No. 141 and SFAS No. 142 as they relate to mineral rights held under lease or other contractual arrangements, and as to whether costs associated with these rights should be classified as intangible assets on the balance sheet, apart from other capitalized oil and gas property costs, and to provide specific footnote disclosure. In March 2004, the Emerging Issues Task Force of the FASB reached a consensus that mineral rights are tangible assets. In April 2004, the FASB ratified the EITF's consensus by issuing FASB Staff Position (FSP) 141-1 and 142-1, which amend SFAS No. 141 and SFAS No. 142 to address the inconsistency between the EITF consensus on EITF Issue No. 04-02 and SFAS No. 141 and SFAS No. 142. The FSP is effective for reporting periods beginning after April 29, 2004 and defines mineral rights as tangible assets. In September 2004, the EITF issued FASB Staff Position (FSP) 142-2, in which the FASB staff further concluded that the costs for acquiring contractual mineral rights in oil and gas properties would continue to be recorded as tangible assets. These staff positions had no impact on our consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46 (Revised December 2003), Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51 Consolidated Financial Statements (the "Interpretation"). The Interpretation significantly changes whether entities included in its scope are consolidated by their sponsors, transferors, or investors. The Interpretation introduces a new consolidation model - the variable interest model; which determines control (and consolidation) based on potential variability in gains and losses of the entity being evaluated for consolidation. The Interpretation provides guidance for determining whether an entity lacks sufficient equity or its equity holders lack adequate decision-making ability. These variable interest entities ("VIEs") are covered by the Interpretation and are to be evaluated for consolidation based on their variable interests. These provisions applied immediately to variable interests in VIEs created after January 31, 2003, and to variable interests in special purpose entities for periods ending after December 15, 2003. The provisions apply for all other types of variable interests in VIEs for periods ending after March 15, 2004. We have no variable interests in VIEs, nor do we have variable interests in special purpose entities. The adoption of this interpretation had no impact on our financial position or results of operations.

In March 2004, the FASB issued an exposure draft that would amend SFAS No. 123 "Accounting for Stock Based Compensation" and SFAS No. 95 "Statement of Cash Flows." This exposure draft was issued to improve existing accounting rules and provide more complete, higher quality information for investors on employee stock compensation matters. This statement is effective for interim or annual periods beginning

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

after June 15, 2005. The exposure draft covers a wide range of equity-based arrangements including stock options. Under the FASB's proposal, share-based payments to employees, including stock options, would be treated the same as other forms of compensation by recognizing the related cost in the income statement. The expense of the award would generally be measured at fair value at the grant date. Current accounting guidance allows that the expense relating to employee stock options to only be disclosed in the footnotes of the financial statements. We are evaluating the effects that will result from future adoption of this proposed statement.

In September 2004, the EITF discussed an issue dealing with how to evaluate whether a partnership should be consolidated by its general partner, EITF Issue 04-5. The issue deals with rights held by the limited partners and how this affects the consolidation of partnerships by the sole general partner in accordance with generally accepted accounting principles, absent the existence of these rights held by the limited partners. The EITF will discuss this issue in the future and we do not believe this staff position will have a material impact on our Consolidated Financial Statements.

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 106 (SAB 106). SAB 106 expresses the SEC staff's views regarding SFAS No. 143 and its impact on both the full-cost ceiling test and the calculation of depletion expense. In accordance with SAB 106, beginning in the fourth quarter of 2004, undiscounted abandonment cost for future wells, not recorded at the present time but needed to develop the proved reserves in existence at the present time, should be included in the unamortized cost of oil and gas properties, net of related salvage value, for purposes of computing DD&A. The effect of including undiscounted abandonment costs of future wells to the undiscounted cost of oil and gas properties will increase depletion expense in future periods, however, we currently do not believe such increases will be material.

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 future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates and assumptions, upon current market conditions, and upon engineering and geologic information available at this time, and is subject to change and to a number of risks and uncertainties, and therefore, actual results may differ materially. Among the factors that could cause actual results to differ materially are volatility in oil and gas prices; fluctuations of the prices received or demand for our oil and natural gas; the uncertainty of drilling results and reserve estimates; operating hazards; requirements for 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.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

Commodity Risk

Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. The effects of such pricing volatility are expected to continue.

Our price-risk management policy permits the utilization of 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 September 30, 2004, we had in place price floors in effect through the March 2005 contract month for natural gas, these cover our domestic natural gas production for October 2004 to March 2005. The natural gas price floors cover notional volumes of 950,000 MMBtu, with a weighted average floor price of \$5.63 per MMBtu. Our natural gas hedges in place at September 30, 2004 are expected to cover approximately 10% to 15% of our domestic natural gas production from October 2004 to March 2005. At September 30, 2004, we also had in place price floors in effect from the January 2005 contract month to the March 2005 contract month for crude oil, that cover our domestic crude oil production for January 2005 to March 2005. The crude oil price floors cover notional volumes of 216,000 barrels, with a weighted average floor price of \$37.00 per barrel. Our crude oil hedges in place at September 30, 2004 are expected to cover approximately 15% to 20% of our domestic crude oil production from January 2005 to March 2005.
- New Zealand Gas Contracts – All of our current gas production in New Zealand is sold under long-term, 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 results of operations.

Foreign Currency Risk

We are exposed to the risk of fluctuations in foreign currencies, most notably the New Zealand dollar. Fluctuations in rates between the New Zealand dollar and U.S. dollar may impact our financial results from our New Zealand subsidiaries since we have receivables, liabilities, natural gas and NGL sales contracts, and New Zealand income tax calculations, all denominated in New Zealand dollars.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS (Continued)

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 September 30, 2004, we had \$6.2 million in borrowings 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 48 basis points and would not have a material adverse effect on our 2004 cash flows based on this same level or a modest level of borrowing.

CONTROLS AND PROCEDURES

Our chief executive officer and chief financial officer have evaluated our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 as of the end of the period covered by the report. Based on that evaluation, they have concluded that such disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to Swift Energy as required under the Exchange Act to be disclosed in this report. There were no significant changes in our internal controls that could significantly affect such controls subsequent to the date of their evaluation.

In conjunction with our preparation toward compliance with Section 404 of the Sarbanes-Oxley Act of 2002, including the required management assessment of the effectiveness of the internal controls over financial reporting, we continue to evaluate, analyze, document and test the Company's internal controls over financial reporting. As part of this process, we are implementing certain enhancements to our internal control over financial reporting. Based on the work performed to date, including internal audit procedures and testing, we are currently not aware of any internal control deficiencies that individually, or in the aggregate, would constitute a material weakness.

Discussions and updates, with respect to the Section 404 process, are regularly held with the Company's independent auditors, the Audit Committee, the Board of Directors and management. The Company can provide no assurance as to whether management or the Company's independent auditors will complete their work on a timely basis necessary for the Company to be in compliance with the SEC's rules. We also can provide no assurances as to management's conclusions, or those of the Company's independent auditors, with respect to the effectiveness of the Company's internal control over financial reporting at December 31, 2004, under Section 404 of the Sarbanes-Oxley Act.

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 2. Sales of Unregistered Securities and Use of Proceeds - None

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.

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: November 8, 2004

By: _____ (original signed by)
Alton D. Heckaman, Jr.
Senior Vice President – Finance and
Chief Financial Officer

Date: November 8, 2004

By: _____ (original signed by)
David W. Wesson
Controller and Principal Accounting
Officer

CERTIFICATION

I, Terry E. Swift, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the period ended September 30, 2004, of Swift Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2004

/s/ Terry E. Swift
Terry E. Swift
President and
Chief Executive Officer

CERTIFICATION

I, Alton D. Heckaman, Jr., certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the period ended September 30, 2004, of Swift Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2004

/s/ Alton D. Heckaman, Jr.
Alton D. Heckaman, Jr.
Senior Vice President – Finance and
Chief Financial Officer

Certification of Chief Executive Officer and Chief Financial Officer

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the accompanying Quarterly Report on Form 10-Q for the period ended September 30, 2004 (the "Report") of Swift Energy Company ("Swift") as filed with the Securities and Exchange Commission on November 8, 2004, the undersigned, in his capacity as an officer of Swift, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Swift.

Dated: November 8, 2004

/s/ Alton D. Heckaman, Jr.
Alton D. Heckaman, Jr.
Senior Vice President-Finance and
Chief Financial Officer

Dated: November 8, 2004

/s/ Terry E. Swift
Terry E. Swift
President and Chief Executive Officer