

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, 2003

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 77060
(281) 874-2700
(Address and telephone number of principal executive offices)

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 Act).

Yes No

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

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

27,444,262 Shares
(Outstanding at October 31, 2003)

SWIFT ENERGY COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2003
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SWIFT ENERGY COMPANY
CONSOLIDATED BALANCE SHEETS

	September 30, 2003 (Unaudited)	December 31, 2002
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ 2,678,315	\$ 3,816,107
Accounts receivable -		
Oil and gas sales	23,335,323	17,360,716
Associated limited partnerships and joint ventures	143,190	191,964
Joint interest owners	1,400,790	3,364,846
Other current assets	4,695,602	5,034,566
Total Current Assets	32,253,220	29,768,199
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties being amortized	1,264,918,011	1,150,633,802
Unproved properties not being amortized	65,642,790	69,603,481
	1,330,560,801	1,220,237,283
Furniture, fixtures, and other equipment	10,204,883	9,595,944
	1,340,765,684	1,229,833,227
Less-Accumulated depreciation, depletion, and amortization	(551,095,515)	(504,323,773)
	789,670,169	725,509,454
Other Assets:		
Deferred income taxes	433,591	2,680,585
Deferred charges	8,279,976	9,047,621
	8,713,567	11,728,206
	\$ 830,636,956	\$ 767,005,859

See accompanying notes to consolidated financial statements.

SWIFT ENERGY COMPANY
CONSOLIDATED BALANCE SHEETS

	September 30, 2003 (Unaudited)	December 31, 2002
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	\$ 51,681,138	\$ 43,028,708
Payable to associated limited partnerships	514,309	91,126
Undistributed oil and gas revenues	5,527,236	3,764,350
Total Current Liabilities	57,722,683	46,884,184
Long-Term Debt	336,233,381	324,271,973
Deferred Income Taxes	39,248,246	30,776,518
Asset Retirement Obligation	9,834,695	---
Commitments and Contingencies		
Stockholders' Equity:		
Preferred stock, \$.01 par value, 5,000,000 shares authorized, none outstanding	---	---
Common stock, \$.01 par value, 85,000,000 shares authorized, 27,968,640 and 27,811,632 shares issued, and 27,441,622 and 27,201,509 shares outstanding, respectively	279,686	278,116
Additional paid-in capital	334,418,690	333,543,471
Treasury stock held, at cost, 527,018 and 610,123 shares, respectively	(7,558,093)	(8,749,922)
Retained earnings	60,571,708	40,179,572
Other comprehensive loss, net of taxes	(114,040)	(178,053)
	387,597,951	365,073,184
	\$ 830,636,956	\$ 767,005,859

See accompanying notes to consolidated financial statements.

SWIFT ENERGY COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three months ended		Nine months ended	
	09/30/03	09/30/02	09/30/03	09/30/02
Revenues:				
Oil and gas sales	\$ 52,087,321	\$ 36,592,329	\$ 157,846,870	\$ 101,536,512
Fees from limited partnerships and joint ventures	5,577	5,830	20,512	59,953
Interest income	26,279	158,664	136,747	190,957
Gain on asset disposition	---	---	---	7,332,668
Price-risk management and other, net	(566,655)	(186,014)	(2,234,085)	375,065
	<u>51,552,522</u>	<u>36,570,809</u>	<u>155,770,044</u>	<u>109,495,155</u>
Costs and Expenses:				
General and administrative, net	3,670,416	2,497,413	10,564,959	7,368,989
Depreciation, depletion and amortization	16,042,377	13,487,437	46,630,689	41,789,711
Accretion of asset retirement obligation	206,475	---	623,761	---
Oil and gas production	13,730,467	11,004,641	39,392,531	30,602,493
Interest expense, net	6,749,419	6,647,968	20,107,188	16,607,651
	<u>40,399,154</u>	<u>33,637,459</u>	<u>117,319,128</u>	<u>96,368,844</u>
Income Before Income Taxes and Cumulative Effect of Change in Accounting Principle	11,153,368	2,933,350	38,450,916	13,126,311
Provision for Income Taxes	4,090,743	986,344	13,681,928	4,575,403
Income Before Cumulative Effect of Change in Accounting Principle	7,062,625	1,947,006	24,768,988	8,550,908
Cumulative Effect of Change in Accounting Principle (net of taxes)	---	---	4,376,852	---
Net Income	<u>\$ 7,062,625</u>	<u>\$ 1,947,006</u>	<u>\$ 20,392,136</u>	<u>\$ 8,550,908</u>
Per share amounts -				
Basic: Income Before Cumulative Effect of Change in Accounting Principle	\$ 0.26	\$ 0.07	\$ 0.91	\$ 0.33
Cumulative Effect of Change in Accounting Principle	---	---	(0.16)	---
Net Income	<u>\$ 0.26</u>	<u>\$ 0.07</u>	<u>\$ 0.75</u>	<u>\$ 0.33</u>
Diluted: Income Before Cumulative Effect of Change in Accounting Principle	\$ 0.26	\$ 0.07	\$ 0.90	\$ 0.32
Cumulative Effect of Change in Accounting Principle	---	---	(0.16)	---
Net Income	<u>\$ 0.26</u>	<u>\$ 0.07</u>	<u>\$ 0.74</u>	<u>\$ 0.32</u>
Weighted Average Shares Outstanding	<u>27,424,195</u>	<u>26,889,186</u>	<u>27,326,169</u>	<u>26,112,382</u>

See accompanying notes to consolidated financial statements.

SWIFT ENERGY COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock (1)	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total
Balance, December 31, 2001	\$ 256,346	\$ 296,172,820	\$ (12,032,791)	\$ 28,256,345	\$ -	\$ 312,652,720
Stock issued for benefit plans (38,149 shares)	292	617,960	127,795	-	-	746,047
Stock options exercised (112,995 shares)	1,130	1,206,413	-	-	-	1,207,543
Public stock offering (1,725,000 shares)	17,250	30,465,809	-	-	-	30,483,059
Employee stock purchase plan (9,801 shares)	98	122,343	-	-	-	122,441
Stock issued in acquisitions (520,000 shares)	3,000	4,958,126	3,155,074	-	-	8,116,200
Comprehensive income:						
Net income	-	-	-	11,923,227	-	11,923,227
Change in fair value of cash flow hedges, net of income tax	-	-	-	-	(178,053)	(178,053)
Total comprehensive income	-	-	-	-	-	11,745,174
Balance, December 31, 2002	<u>\$ 278,116</u>	<u>\$ 333,543,471</u>	<u>\$ (8,749,922)</u>	<u>\$ 40,179,572</u>	<u>\$ (178,053)</u>	<u>\$ 365,073,184</u>
Stock issued for benefit plans (83,201 shares) (2)	1	(408,178)	1,191,829	-	-	783,652
Stock options exercised (100,338 shares) (2)	1,003	869,450	-	-	-	870,453
Employee stock purchase plan (56,574 shares) (2)	566	413,947	-	-	-	414,513
Comprehensive income:						
Net income (2)	-	-	-	20,392,136	-	20,392,136
Change in fair value of cash flow hedges, net of income tax (2)	-	-	-	-	64,013	64,013
Total comprehensive income (2)	-	-	-	-	-	20,456,149
Balance, September 30, 2003 (2)	<u>\$ 279,686</u>	<u>\$ 334,418,690</u>	<u>\$ (7,558,093)</u>	<u>\$ 60,571,708</u>	<u>\$ (114,040)</u>	<u>\$ 387,597,951</u>

(1)\$.01 par value

(2) Unaudited

See accompanying notes to consolidated financial statements.

SWIFT ENERGY COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Period Ended September 30,	
	2003	2002
Cash Flows From Operating Activities:		
Net income	\$ 20,392,136	\$ 8,550,908
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	46,630,689	41,789,711
Accretion of asset retirement obligation	623,761	---
Deferred income taxes	13,375,807	4,554,165
Gain on asset disposition	---	(7,332,668)
Other	658,524	728,917
Change in assets and liabilities -		
(Increase) decrease in accounts receivable, excluding income taxes receivable	(3,895,748)	1,263,553
Increase in accounts payable and accrued liabilities	1,860,038	5,539,810
Decrease in income taxes receivable	---	600,000
Net Cash Provided by Operating Activities	84,022,059	55,694,396
Cash Flows From Investing Activities:		
Additions to property and equipment	(101,510,935)	(132,521,779)
Proceeds from the sale of property and equipment	3,839,714	11,525,547
Net cash distributed as operator of oil and gas properties	(989,176)	(4,247,012)
Net cash received (distributed) as operator of partnerships and joint ventures	471,957	(26,527,633)
Other	(89,635)	68,388
Net Cash Used in Investing Activities	(98,278,075)	(151,702,489)
Cash Flows From Financing Activities:		
Proceeds from long-term debt	---	200,000,000
Net proceeds from (payments of) bank borrowings	11,900,000	(129,500,000)
Net proceeds from issuances of common stock	1,218,224	31,330,384
Payments of debt issuance costs	---	(6,257,428)
Net Cash Provided by Financing Activities	13,118,224	95,572,956
Net Decrease in Cash and Cash Equivalents	(1,137,792)	(435,137)
Cash and Cash Equivalents at Beginning of Period	3,816,107	2,149,086
Cash and Cash Equivalents at End of Period	<u>\$ 2,678,315</u>	<u>\$ 1,713,949</u>
<u>Supplemental disclosures of cash flows information:</u>		
Cash paid during period for interest, net of amounts capitalized	\$ 17,825,296	\$ 10,511,529
Cash paid during period for income taxes	\$ 306,121	\$ 2,500
<u>Non-cash investing activity:</u>		
Issuance of common stock in acquisitions	\$ ---	\$ 8,116,200

See accompanying notes to consolidated financial statements.

SWIFT ENERGY COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
SEPTEMBER 30, 2003 (UNAUDITED) AND DECEMBER 31, 2002

(1) GENERAL INFORMATION

The consolidated financial statements included herein have been prepared by Swift Energy Company and are unaudited, except for the balance sheet at December 31, 2002, which has been prepared from the audited financial statements at that date. The financial statements reflect necessary adjustments, all of which were of a recurring nature, and are in the opinion of our management necessary for a fair presentation. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission. We believe that the disclosures presented are adequate to allow the information presented not to be misleading. The 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. Under the full-cost method of accounting, 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. Interest costs related to unproved properties are also capitalized to unproved oil and gas properties. Interest not capitalized and general and administrative costs related to production and general overhead are expensed as incurred. Our interests in oil and gas properties and partnerships are proportionately consolidated.

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 (net of salvage value)—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. 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.

SWIFT ENERGY COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-CONTINUED
SEPTEMBER 30, 2003 (UNAUDITED) AND DECEMBER 31, 2002

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 and capitalized asset retirement obligations, net of related salvage values and deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using hedge adjusted period-end prices, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects ("Ceiling Test"). 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 additional non-cash write-downs of oil and gas properties could occur in the future.

Accounts Receivable

Included in the total "Accounts receivable" balance, which totaled \$24.9 million at September 30, 2003 on the accompanying balance sheet, was approximately \$2.3 million of receivables related to disputed volumes produced from 2001 and 2002. Due to this dispute, we have not recorded a receivable to date with regard to 2003 volumes.

We assess the collectibility of trade and other receivables. Based on our judgment, we would accrue a reserve when we believe a receivable may not be collected. At September 30, 2003 and December 31, 2002, we had an allowance for doubtful accounts of \$771,354 and \$291,136, respectively.

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.

SWIFT ENERGY COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-CONTINUED
SEPTEMBER 30, 2003 (UNAUDITED) AND DECEMBER 31, 2002

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. 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, 2003 and 2002:

		Three Months Ended September 30,					
		2003			2002		
		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	\$ 7,062,625	27,424,195	\$.26	\$ 1,947,006	26,889,186	\$.07
	Stock Options	---	259,246		---	242,283	
Diluted EPS:							
	Net Income Before Cumulative Effect of Change in Accounting Principle and Assumed Share Conversions	\$ 7,062,625	27,683,441	\$.26	\$ 1,947,006	27,131,469	\$.07
		Nine Months Ended September 30,					
		2003			2002		
		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	\$ 24,768,988	27,326,169	\$.91	\$ 8,550,908	26,112,382	\$.33
	Stock Options	---	147,158		---	368,786	
Diluted EPS:							
	Net Income Before Cumulative Effect of Change in Accounting Principle and Assumed Share Conversions	\$ 24,768,988	27,473,327	\$.90	\$ 8,550,908	26,481,168	\$.32

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

SWIFT ENERGY COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-CONTINUED
SEPTEMBER 30, 2003 (UNAUDITED) AND DECEMBER 31, 2002

Other Comprehensive Loss

We follow the provisions of SFAS No. 130 "Reporting Comprehensive Income," which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At September 30, 2003, we recorded \$178,188, net of taxes of \$64,148, of derivative losses in "Other comprehensive loss" on the accompanying balance sheet. The components of accumulated other comprehensive loss and related tax effects for the nine months ended September 30, 2003 were as follows:

	<u>Gross Value</u>	<u>Tax Effect</u>	<u>Net of Tax Value</u>
Balance at December 31, 2002	\$ 278,208	\$ 100,155	\$ 178,053
Change in fair value of cash flow hedges	1,891,210	680,836	1,210,374
Effect of cash flow hedges settled during the period	<u>(1,991,230)</u>	<u>(716,843)</u>	<u>(1,274,387)</u>
Balance at September 30, 2003	<u>\$ 178,188</u>	<u>\$ 64,148</u>	<u>\$ 114,040</u>

Total comprehensive income was \$7.3 million and \$1.8 million for the third quarters of 2003 and 2002. For the nine-month periods ended September 30, 2003 and 2002, total comprehensive income was \$20.5 million and \$8.4 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. Had compensation expense for these plans been determined based on the fair value of the options using the Black-Scholes option pricing model, and 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>2003</u>	<u>2002</u>
Net Income:	As Reported	\$7,062,625	\$1,947,006
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	<u>(1,024,734)</u>	<u>(1,110,573)</u>
	Pro Forma	\$6,037,891	\$836,433
Basic EPS:	As Reported	\$.26	\$.07
	Pro Forma	\$.22	\$.03
Diluted EPS:	As Reported	\$.26	\$.07
	Pro Forma	\$.22	\$.03

SWIFT ENERGY COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-CONTINUED
SEPTEMBER 30, 2003 (UNAUDITED) AND DECEMBER 31, 2002

		Nine Months Ended September 30,	
		2003	2002
Net Income:	As Reported	\$20,392,136	\$8,550,908
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(3,048,052)	(3,321,059)
	Pro Forma	\$17,344,084	\$5,229,849
Basic EPS:	As Reported	\$.75	\$.33
	Pro Forma	\$.63	\$.20
Diluted EPS:	As Reported	\$.74	\$.32
	Pro Forma	\$.63	\$.20

Pro forma compensation cost reflected above may not be representative of the cost to be expected in future periods.

Price-Risk Management Activities

We follow SFAS No. 133, which requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. The statement also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or a liability measured at its fair value. Special hedge accounting for qualifying hedges would allow the gains and losses on derivatives to offset related results on the hedged item in the consolidated statements of income and would require that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting.

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 protection price floors and collars. During the third quarters of 2003 and 2002, we recognized net losses of \$598,766 and \$181,595, respectively, relating to our derivative activities. During the first nine months of 2003 and 2002 we recognized net losses of \$2,399,435 and \$201,474, respectively, relating to our derivative activities. Approximately \$5,789 and \$162,727 of the losses recognized in the 2003 and 2002 periods, respectively, were unrealized, as the contracts were still open. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. At September 30, 2003, we had recorded \$178,188 of derivative losses, net of tax effects of \$64,148, 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 2003 was 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, 2003, we had in place price floors in effect through the December 2003 contract month for natural gas and through November 2003 for crude oil. The natural gas price floors cover notional volumes of 1,050,000 MMBtu with a weighted average floor price of \$4.75 per MMBtu. The crude oil price floors cover notional volumes of 180,000 barrels of oil, with a weighted average floor price of \$27.58 per barrel. When we entered into the preceding transactions, with the exception of several November natural gas floors, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of our oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and qualifies as a cash flow hedge, to the extent that the hedge is effective, are initially recorded in Other Comprehensive Income (Loss). When the hedged transactions are recorded upon the actual sale of oil

SWIFT ENERGY COMPANY
 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-CONTINUED
 SEPTEMBER 30, 2003 (UNAUDITED) AND DECEMBER 31, 2002

and natural gas, these gains or losses are transferred from “Other comprehensive income (loss)” and recorded in “Price-risk management and other, net” on the consolidated statement of income. Several of our November contract month natural gas floors became ineffective, as accounted for under special hedge accounting treatment, during the second quarter of 2003. These natural gas floors have been marked to market each period with any gain or loss recorded in “Price-risk management and other, net” on the 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. At September 30, 2003, the fair values of the derivative instruments were as follows: gas price floors represented an asset of \$322,080 and crude oil price floors represented an asset of \$95,899. These instruments are 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. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated 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 following provides a roll-forward of our asset retirement obligation:

Asset Retirement Obligation recorded as of January 1, 2003	\$ 8,934,320
Accretion expense for the nine months ended September 30, 2003	623,761
Additions due to new wells and facilities construction	546,350
Reductions due to sold and abandoned wells	(332,327)
Increase due to currency exchange rate fluctuations	62,591
Asset Retirement Obligation as of September 30, 2003	<u>\$ 9,834,695</u>

The pro forma effect on the first quarter of 2002, assuming adoption of SFAS No. 143 effective January 1, 2002, would have included a non-cash charge of \$3.7 million (net of \$2.1 million of deferred taxes), which would have been recorded as a Cumulative Effect of Change in Accounting Principle. The following table displays our pro forma results for the three and nine months ended September 30, 2002, had we adopted SFAS No. 143 effective January 1, 2002.

SWIFT ENERGY COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-CONTINUED
SEPTEMBER 30, 2003 (UNAUDITED) AND DECEMBER 31, 2002

	<u>Three Months Ended</u> <u>September 30, 2002</u>		<u>Nine Months Ended</u> <u>September 30, 2002</u>
Net Income:			
Actual – as reported	\$ 1,947,006	\$	8,550,908
Pro Forma	\$ 1,841,047	\$	4,520,396
Basic EPS:			
Actual – as reported	\$.07	\$.33
Pro Forma	\$.07	\$.17
Diluted EPS:			
Actual – as reported	\$.07	\$.32
Pro Forma	\$.07	\$.17

New Accounting Principles

In January 2003, the FASB issued Interpretation No. 46 “Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51” (the “Interpretation”). The Interpretation will significantly change 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. These provisions apply immediately to variable interests in VIE’s created after January 15, 2003 and are effective for periods ending after December 15, 2003 for VIE’s in which the Company holds a variable interest that it acquired prior to February 1, 2003. The Company is still evaluating the impact of this new interpretation.

In May 2003, the FASB issued SFAS No. 150 “Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.” This statement sets standards for classifying and measuring certain financial instruments with characteristics of both liabilities and equity. This statement is effective for periods ending after December 15, 2003. The Company is still evaluating the impact of this new interpretation.

The Securities and Exchange Commission (“SEC”) commented that acquired oil and gas drilling rights should be classified as an intangible asset pursuant to FASB No. 142 “Goodwill and Other Intangible Assets.” The SEC has not required companies to apply this classification and we classify the costs of oil and gas drilling rights as property and equipment. The Emerging Issues Task Force, a subset of FASB, will address this issue at a later date. If the SEC’s comment on this issue is adopted in the future, we may be required to reclassify these costs from property and equipment to intangible assets on our balance sheet.

SWIFT ENERGY COMPANY
 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-CONTINUED
 SEPTEMBER 30, 2003 (UNAUDITED) AND DECEMBER 31, 2002

(3) LONG-TERM DEBT

Our long-term debt as of September 30, 2003 and December 31, 2002, is as follows:

	September 30, 2003	December 31, 2002
Bank Borrowings	\$ 11,900,000	\$ ---
Senior Notes due 2009	124,333,381	124,271,973
Senior Notes due 2012	200,000,000	200,000,000
Long-Term Debt	<u>\$ 336,233,381</u>	<u>\$ 324,271,973</u>

The unamortized discount on the Senior Notes due 2009 was \$666,619 and \$728,027 at September 30, 2003 and December 31, 2002, respectively.

Bank Borrowings

Under our \$300.0 million credit facility with a syndicate of ten banks, at September 30, 2003 we had \$11.9 million in outstanding borrowings and no outstanding borrowings at year-end 2002. At September 30, 2003, the credit facility consisted of a \$300.0 million secured revolving line of credit with a \$150.0 million commitment amount. The interest rate is either (a) the lead bank's prime rate (4% at September 30, 2003) 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. Of the \$11.9 million borrowed at September 30, 2003, \$5.0 million was borrowed at the LIBOR rate plus applicable margin, which was 2.37%. Our credit facility extends until October 1, 2005.

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 Company stock of \$15.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to working capital, debt, and equity ratios), and limitations on incurring other debt or repurchasing our existing Senior Notes. 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 recently reconfirmed by our bank group and increased to \$250.0 million effective November 1, 2003, an increase of \$55.0 million from the previous level of \$195.0 million. We previously 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 2004.

SWIFT ENERGY COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-CONTINUED
SEPTEMBER 30, 2003 (UNAUDITED) AND DECEMBER 31, 2002

Senior Notes Due 2009

At September 30, 2003, our Senior Notes due 2009 consisted of \$125.0 million of 10.25% Senior Subordinated Notes due 2009. These Senior Notes were issued at 99.236% of the principal amount on August 4, 1999, and will mature on August 1, 2009. The notes are unsecured senior subordinated obligations and are subordinated in right of payment to all our existing and future senior debt, including our bank debt. Interest on these Senior Notes is payable semiannually on February 1 and August 1. On or after August 1, 2004, these notes are redeemable for cash at the option of Swift, with certain restrictions, at 105.125% of principal, declining to 100% in 2007. Upon certain changes in control of Swift, each holder of these notes will have the right to require Swift to repurchase the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these Senior Notes include, among other restrictions, a limit on repurchases by Swift of its common stock. We are currently in compliance with the provisions of the indenture governing the these notes.

Senior Notes Due 2012

At September 30, 2003, our Senior Notes due 2012 consisted of \$200.0 million of 9.375% Senior Subordinated Notes due 2012. These Senior Notes were issued at 100% of the principal amount on April 11, 2002, and will mature on May 1, 2012. The notes are unsecured senior subordinated obligations and are subordinated in right of payment to all our existing and future senior debt, including our bank debt. Interest on these Senior Notes is payable semiannually on May 1 and November 1. On or after May 1, 2007, these notes are redeemable for cash at the option of Swift, with certain restrictions, at 104.688% of principal, declining to 100% in 2010. In addition, prior to May 1, 2005, we may redeem up to 33.33% of the Senior Notes with the proceeds of qualified offerings of our equity at 109.375% of the principal amount of these notes, together with accrued and unpaid interest. Upon certain changes in control of Swift, each holder of Senior Notes will have the right to require Swift to repurchase the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of our these Senior Notes include, among other restrictions, a limit on repurchases by Swift of its common stock. We are currently in compliance with the provisions of the indenture governing these notes.

(4) STOCKHOLDERS' EQUITY

In March 2002, we issued 220,000 shares of our common stock, along with cash consideration as an effective date adjustment, to acquire all of the New Zealand assets of Antrim Oil and Gas Limited ("Antrim"). At the time, these 220,000 shares, with a fair market value of \$4.2 million, were issued out of treasury shares, and resulted in an increase to paid-in capital of \$1.0 million and a decrease in the value of our treasury shares of \$3.2 million. In April 2002, we issued 1,725,000 shares of common stock in a public offering, at a price of \$18.25 per share. Gross proceeds from this offering were \$31,481,250, with issuance costs of \$998,191. In September 2002, we issued 300,000 shares of our common stock with a fair market value of \$3.9 million, along with \$2.7 million in cash, to acquire the interests owned by Bligh Oil and Minerals N.L. ("Bligh") in the Swift operated Rimu/Kauri and TAWN permits, mining licenses and facilities in New Zealand.

(5) FOREIGN ACTIVITIES

As of September 30, 2003, our gross capitalized oil and gas property costs in New Zealand totaled approximately \$200.1 million. Approximately \$166.0 million has been included in the proved properties portion of our oil and gas properties, while \$34.1 million is included as unproved properties. Our functional currency in New Zealand is the U.S. dollar.

SWIFT ENERGY COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-CONTINUED
SEPTEMBER 30, 2003 (UNAUDITED) AND DECEMBER 31, 2002

(6) SEGMENT INFORMATION

Below is a summary of financial information by country:

	Three Months Ended September 30,					
	2003			2002		
	Domestic	New Zealand	Total	Domestic	New Zealand	Total
Oil and gas sales	\$ 39,974,435	\$ 12,112,886	\$ 52,087,321	\$ 28,454,804	\$ 8,137,525	\$ 36,592,329
Costs and Expenses:						
Depreciation, depletion and amortization	11,645,480	4,396,897	16,042,377	10,196,179	3,291,258	13,487,437
Accretion of asset retirement obligation	151,188	55,287	206,475	---	---	---
Oil and gas production	10,260,211	3,470,256	13,730,467	8,444,530	2,560,111	11,004,641
Income from oil and gas operations	\$ 17,917,556	\$ 4,190,446	\$ 22,108,002	\$ 9,814,095	\$ 2,286,156	\$ 12,100,251
Other revenues (1)			(534,799)			(21,520)
General and administrative, net			3,670,416			2,497,413
Interest expense, net			6,749,419			6,647,968
Income before income taxes and Cumulative Effect of Change in Accounting Principle			<u>\$ 11,153,368</u>			<u>\$ 2,933,350</u>
	Nine Months Ended September 30,					
	2003			2002		
	Domestic	New Zealand	Total	Domestic	New Zealand	Total
Oil and gas sales	\$ 123,693,311	\$ 34,153,559	\$ 157,846,870	\$ 82,202,092	\$ 19,334,420	\$ 101,536,512
Costs and Expenses:						
Depreciation, depletion and amortization	32,508,198	14,122,491	46,630,689	34,210,133	7,579,578	41,789,711
Accretion of asset retirement obligation	448,711	175,050	623,761	---	---	---
Oil and gas production	29,532,116	9,860,415	39,392,531	25,141,686	5,460,807	30,602,493
Income from oil and gas operations	\$ 61,204,286	\$ 9,995,603	\$ 71,199,889	\$ 22,850,273	\$ 6,294,035	\$ 29,144,308
Other revenues (1)			(2,076,826)			7,958,643
General and administrative, net			10,564,959			7,368,989
Interest expense, net			20,107,188			16,607,651
Income before income taxes and Cumulative Effect of Change in Accounting Principle			<u>\$ 38,450,916</u>			<u>\$ 13,126,311</u>
Property, Plant and Equipment, net	<u>\$ 616,251,046</u>	<u>\$ 173,419,123</u>	<u>\$ 789,670,169</u>	<u>\$ 551,583,952</u>	<u>\$ 158,976,243</u>	<u>\$ 710,560,195</u>

(1) Other revenues consist of Fees from limited partnerships and joint ventures, Interest income, Gain on asset disposition and Price-risk management and other, net on the accompanying consolidated statements of income.

SWIFT ENERGY COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-CONTINUED
SEPTEMBER 30, 2003 (UNAUDITED) AND DECEMBER 31, 2002

(7) ACQUISITIONS AND DISPOSITIONS

New Zealand. Through our subsidiary, Swift Energy New Zealand Limited (“SENZ”), we acquired Southern Petroleum (NZ) Exploration Limited (“Southern NZ”) in January 2002 for approximately \$51.4 million in cash. We allocated \$36.1 million of the acquisition price to “Proved properties,” \$10.0 million to “Unproved properties,” \$4.9 million to “Deferred income taxes” and \$0.4 million to “Other current assets” on our Consolidated Balance Sheet. Southern NZ was an affiliate of Shell New Zealand and owns interests in four onshore producing oil and gas fields, hydrocarbon processing facilities, and pipelines connecting the fields and facilities to export terminals and markets. This acquisition was accounted for by the purchase method of accounting.

In March 2002, we purchased through our subsidiary, SENZ, all of the New Zealand assets owned by Antrim for 220,000 shares of Swift Energy Company common stock valued at \$4.2 million with an effective date adjustment of approximately \$0.5 million for total consideration of \$4.7 million.

In September 2002, we purchased through our subsidiary, SENZ, Bligh’s 5% working interest in permit 38719 and 5% interest in the Rimu petroleum mining permit 38151, along with its 3.24% working interest in the four TAWN petroleum mining licenses, for 300,000 shares of Swift Energy Company common stock valued at \$3.9 million, along with \$2.7 million in cash for total consideration of \$6.6 million.

Russia. In 1993, we entered into a Participation Agreement with Senega, a Russian Federation joint stock company, to assist in the development and production of reserves from two fields in western Siberia and received a 5% net profits interest. We also purchased a 1% net profits interest. Our investment in Russia was fully impaired in the third quarter of 1998. In March 2002, we received \$7.5 million for our investment in Russia. Although the proceeds from sales of oil and gas properties are generally treated as a reduction of oil and gas property costs, because we had previously charged to expense all \$10.8 million of cumulative costs relating to our Russian activities, this cash payment, net of transaction expenses, resulted in recognition of a \$7.3 million non-recurring gain on asset disposition in the first quarter of 2002.

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

GENERAL

Over the last several years, we have emphasized adding reserves through drilling activity, while adding reserves through strategic purchases of producing properties when oil and gas prices were at lower levels and other market conditions were appropriate. We used this flexible strategy of employing both drilling and acquisitions to add more reserves than we depleted through production during such period.

CONTRACTUAL COMMITMENTS AND OBLIGATIONS

Our contractual commitments for the remainder of 2003 and the next four years and thereafter as of September 30, 2003 are as follows:

	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>Thereafter</u>	<u>Total</u>
Non-cancelable operating lease commitments	\$ 547,591	\$ 2,191,495	\$ 523,755	\$ 190,676	\$ 190,676	\$ 186,834	\$ 3,831,027
Capital commitments due to pipeline operators	400,426	--	--	--	--	--	400,426
Asset Retirement Obligation (1)	1,068,558	651,679	--	3,441,209	300,079	4,373,170	9,834,695
Drilling Rig Commitments	2,535,000	--	--	--	--	--	2,535,000
Senior Notes due 2009 (2)	--	--	--	--	--	125,000,000	125,000,000
Senior Notes due 2012 (2)	--	--	--	--	--	200,000,000	200,000,000
Credit Facility which expires in October 2005 (3)	--	--	<u>11,900,000</u>	--	--	--	<u>11,900,000</u>
	<u>\$ 4,551,575</u>	<u>\$ 2,843,174</u>	<u>\$ 12,423,755</u>	<u>\$ 3,631,885</u>	<u>\$ 490,755</u>	<u>\$ 329,560,004</u>	<u>\$ 353,501,148</u>

- (1) Amounts shown by year are the net present value, discounted to September 30, 2003.
- (2) These amounts do not include the interest obligation, which is paid semiannually.
- (3) 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. Worldwide supply disruptions, such as the reduction in crude oil production from Venezuela, together with perceived risks associated with the war between the United States and Iraq, along with other factors, have caused the price of oil to increase significantly in the first nine months of 2003 when compared to historical prices. Other factors such as actions taken by OPEC, worldwide economic conditions, and weather conditions can cause wide fluctuations in the price of oil. Natural gas prices increased significantly in the first quarter of 2003 when compared to historical prices, and have since declined somewhat. 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 wide fluctuations in the price of natural gas. All of such factors are beyond our control.

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

LIQUIDITY AND CAPITAL RESOURCES

During the first nine months of 2003, we largely relied upon our net cash provided by operating activities of \$84.0 million and proceeds from bank borrowings of \$11.9 million to fund capital expenditures of \$101.5 million. During the first nine months of 2002, we principally relied upon our net cash provided by operating activities of \$55.7 million, net proceeds from the public issuance of long-term debt of \$195.0 million and net proceeds of our public stock offering of \$30.5 million, less the repayment of bank borrowings of \$129.5 million, to fund capital expenditures of \$132.5 million.

Net Cash Provided by Operating Activities. For the first nine months of 2003, net cash provided by our operating activities was \$84.0 million, representing a 51% increase as compared to \$55.7 million generated during the first nine months of 2002. The \$28.3 million increase was primarily due to an increase of \$56.3 million in oil and gas sales for the first nine months of 2003, attributable to higher commodity prices and production, offset in part by production cost increases due to significant Lake Washington facility enhancements and workovers, along with scheduled plant shutdowns for maintenance in New Zealand and an increase in interest expense attributed to the replacement of our bank borrowings in April 2002 with the Senior Notes due 2012 that carry a higher interest rate and a longer term.

Accounts Receivable. In early 2003, a dispute arose with a third party regarding the level of volumes we produced and delivered through a gathering system covered by a production handling agreement. Outside audits were conducted related to these volumes produced and delivered to such third party during 2001, 2002 and a portion of 2003. As a result of these audits, we have made claim for payment of additional volumes produced during those periods. Included in the accompanying consolidated balance sheet is approximately \$2.3 million of receivables related to these disputed volumes produced in 2001 and 2002. Due to this dispute, we have not recorded a receivable to date with regard to 2003 volumes. We believe that we will prevail in this dispute and currently anticipate mediation, arbitration or legal action to resolve this claim.

Existing Credit Facility. We had \$11.9 million in outstanding borrowings under our credit facility at September 30, 2003, and no outstanding borrowings at December 31, 2002. At September 30, 2003, our credit facility consisted of a \$300.0 million revolving line of credit with a \$150.0 million commitment amount. The borrowing base is re-determined at least every six months and was recently reconfirmed by our bank group and increased to \$250.0 million, effective November 1, 2003, an increase of \$55.0 million from the previous level of \$195.0 million. We previously 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. Our revolving credit facility includes, among other restrictions, requirements as to maintenance of certain minimum financial ratios (principally pertaining to working capital, debt, and equity ratios), and limitations on incurring other debt. We are in compliance with the provisions of this agreement.

Debt Maturities. Our credit facility extends until October 1, 2005. Our \$125.0 million Senior Notes mature August 1, 2009 and our \$200.0 million Senior Notes mature May 1, 2012.

Working Capital. Our working capital decreased from a deficit of \$17.1 million at December 31, 2002, to a deficit of \$25.5 million at September 30, 2003. The decrease was primarily due to an increase in accrued liabilities due to our drilling activities in the first nine months of 2003.

Capital Expenditures. During the first nine months of 2003, we used \$101.5 million to fund capital expenditures for property, plant, and equipment. These capital expenditures included:

Domestic activities of \$77.3 million as follows:

- \$53.6 million for drilling costs, both development and exploratory;

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

- \$14.2 million for the construction of production and surface facilities, mainly in our Lake Washington area.
- \$7.6 million of domestic prospect costs, principally prospect leasehold, seismic and geological costs of unproved prospects;
- \$1.5 million of producing property acquisitions; and
- \$0.4 million primarily for computer equipment, software, furniture, and fixtures.

New Zealand activities of \$24.2 million as follows:

- \$14.7 million for drilling costs, both development and exploratory;
- \$4.8 million on prospect costs, principally seismic and geological costs;
- \$4.2 million for the construction of production facilities and pipelines;
- \$0.3 million for property acquisitions; and
- \$0.2 million for fixed assets.

We have spent considerable time and capital in 2003 on significant facility capacity upgrades in the Lake Washington field to increase facility capacity to more than 20,000 barrels per day ('b/d') for crude oil up from 9,000 b/d capacity in the first quarter 2003. Facility upgrades, most of which have been recently completed, and the commissioning of these upgrades, have led to numerous planned production shut-in periods during the third and fourth quarters 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 drilled or participated in drilling 48 domestic development wells and seven domestic exploratory wells in the first nine months of 2003, 42 of the development wells and five exploratory wells were in the Lake Washington area. Five domestic exploratory wells and 40 of the domestic development wells were completed. In New Zealand, the Kauri-E1, Kauri-E2 and Kauri-F1 were completed, while the Kauri-A4 began producing into the Rimu Production Station (RPS). The re-entry of the Tuihu exploration well was plugged and abandoned in October 2003.

For the remaining three months of 2003, we expect to make capital expenditures of approximately \$48 to \$55 million (depending on the level and costs of actual drilling activities and on commodity prices). We anticipate that our fourth quarter 2003's internally generated cash flows together with our available bank borrowings, will be sufficient to finance our remaining 2003 capital expenditures. We currently estimate total capital expenditures for 2003 to be approximately \$150 to \$157 million. Capital expenditures for 2002 were \$155.2 million.

During the last three months of 2003, we anticipate drilling or participating in the drilling of up to an additional 23 domestic wells, with an emphasis in the Lake Washington area while undertaking activity in our Brookeland, Masters Creek and South Texas areas again. Our capital projects also include facility upgrades and planning for our 3-D seismic work in Lake Washington. In addition, we plan on drilling an additional well in New Zealand.

Our 2003 capital expenditures continue to be focused on developing and producing long-lived oil reserves in Lake Washington and in the Rimu/Kauri area in New Zealand. With this focus, we expect our 2003 total

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

production to increase by 7% to 9% over 2002 levels primarily from the Lake Washington and TAWN areas, while 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. This drilling focus should help add long-lived oil reserves and should help develop an overall lesser production decline curve, which would extend our average reserve life and emphasize the balancing of our reserves between oil and gas.

We currently anticipate that our capital expenditures for 2004 will range between \$150 and \$170 million. Depending on a number of factors, such as commodity pricing, production levels, and the level and success of planned non-core property dispositions, our internally generated cash flows are expected to fund a majority of these expenditures. Although current plans do not call for extensive use of our bank credit facility in 2004, we believe that our recently increased bank borrowing base will continue to stay at or near its current level, as our proved reserve base continues to grow. If oil and gas prices were to drop precipitously on a sustained basis, it would negatively affect our liquidity and cash flows, including our ability to stay in compliance with certain financial covenants under our credit facility. We would reduce the level of our capital expenditures in response to any such precipitous drop in prices, as we would deem necessary.

RESULTS OF OPERATIONS – Three Months Ended September 30, 2003 and 2002

Revenues. Our revenues in the third quarter of 2003 increased by 41% to \$51.6 million compared to revenues of \$36.6 million in the same period in 2002, primarily due to increases in oil and gas prices and our increased production.

Oil and gas sales revenues of \$52.1 million in the third quarter of 2003 increased by 42%, or \$15.5 million, from the level of those revenues for the comparable 2002 period. Our net sales volumes of 13.6 Bcfe in the third quarter of 2003 increased by 12%, or 1.4 Bcfe, over net sales volumes in the comparable 2002 period. Average prices received for oil increased to \$29.24 per Bbl in the third quarter of 2003 from \$26.17 per Bbl in the comparable 2002 period. Average gas prices received increased to \$3.17 per Mcf in the third quarter of 2003 from \$2.32 per Mcf in the 2002 period. Average natural gas liquids (Ngl) prices increased to \$16.81 per Bbl in the third quarter of 2003 from \$13.58 per Bbl in the comparable 2002 period. The increase in production during the 2003 period was predominantly from our Lake Washington and New Zealand areas.

In the third quarter of 2003, our \$15.5 million increase in oil and gas sales resulted from:

- Price variances that had a \$9.8 million favorable impact on sales, of which \$5.7 million was attributable to the 37% increase in average gas prices received and \$4.1 million was attributable to the 15% increase in the average combined oil and Ngl prices received; and
- Volume variances that had a \$5.7 million favorable impact on sales, with \$5.9 million of the increase coming from the 256,000 Bbl increase in oil and Ngl sales volumes, offset by a \$0.2 million decrease coming from the 0.1 Bcf decrease in gas sales volumes.

SWIFT ENERGY COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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The following table provides additional information regarding the changes in the sources of our oil and gas sales and volumes from our domestic core areas and New Zealand:

<u>Area</u>	Three Months Ended September 30,			
	Revenues (In Millions)		Net Sales Volumes (Bcfe)	
	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>
AWP Olmos	\$ 10.5	\$ 7.9	2.3	2.8
Brookeland	3.9	3.2	1.0	0.8
Lake Washington	16.6	5.2	3.5	1.2
Masters Creek	5.6	8.1	1.3	2.1
Other	3.4	4.1	0.6	1.2
Total Domestic	\$ 40.0	\$ 28.5	8.7	8.1
Rimu/Kauri	3.5	1.4	1.0	0.7
TAWN	8.6	6.7	3.9	3.4
Total New Zealand	\$ 12.1	\$ 8.1	4.9	4.1
Total	\$ 52.1	\$ 36.6	13.6	12.2

Our drilling efforts in the third quarter of 2003 have focused on Lake Washington, South Texas and New Zealand.

The following table provides additional information regarding our oil 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>
2002							
Three Months Ended September 30:							
Domestic	517	169	4.0	8.1	\$26.95	\$14.42	\$3.06
New Zealand	166	56	2.8	4.1	\$23.76	\$11.03	\$1.28
Total	683	225	6.8	12.2	\$26.17	\$13.58	\$2.32
2003							
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	917	247	6.7	13.6	\$29.24	\$16.81	\$3.17

During the third quarter of 2003, we recognized net losses of \$0.6 million relating to our hedging activities, as compared to net losses of \$0.2 million in the 2002 period. This activity is recorded in "Price-risk management and other, net" on the accompanying consolidated statement of income.

Revenues from our oil and gas sales comprised substantially all of net revenues for the third quarters of 2003 and 2002. Natural gas production made up 49% of our production volumes in the third quarter of 2003 and 55% in the 2002 period.

Costs and Expenses. Our expenses in the third quarter of 2003 increased \$6.8 million, or 20%, compared to the 2002 period expenses. The majority of this increase was due to our increased depletion expense and oil and gas production costs, both domestically and in New Zealand.

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

Our net general and administrative expense in the third quarter of 2003, increased \$1.2 million, or 47%, from the level of such expenses in the comparable 2002 period. These increases reflect additional costs needed to run our increased activities in New Zealand, an increase in franchise tax expense, and increased costs related to our corporate governance activities and compliance with the Sarbanes-Oxley Act. Our general and administrative expenses per Mcfe produced increased to \$0.27 per Mcfe in the third quarter of 2003 from \$0.20 per Mcfe in the comparable 2002 period. The portion of supervision fees netted from general and administrative expenses was \$0.8 million for the both the third quarters of 2003 and 2002.

Depreciation, depletion, and amortization of our assets, or DD&A, increased \$2.6 million, or 19%, in the third quarter of 2003 from the 2002 period. Domestically, DD&A increased \$1.4 million due to increased production in the 2003 period, offset somewhat by higher reserve volumes that were added primarily through our Lake Washington activities. In New Zealand, our production increased in the 2003 period in both the Rimu/Kauri and TAWN areas, which increased DD&A in the third quarter 2003. Our DD&A rate per Mcfe of production was \$1.18 in the third quarter of 2003 and \$1.10 in the comparable 2002 period, reflecting these variations in per unit cost of reserves additions.

We recorded \$0.2 million of accretion on our asset retirement obligation in the third quarter of 2003 associated with the adoption of SFAS No. 143 implemented effective January 1, 2003.

Our production costs increased \$2.7 million in the third quarter of 2003, or 25%, and were \$1.01 and \$0.90 per Mcfe in the third quarter of 2003 and 2002, respectively. Due to the 18% increase in production during the third quarter of 2003, our New Zealand operations contributed \$0.9 million of the cost increase in the period. Domestic severance taxes increased \$1.3 million in the third quarter of 2003, due to higher commodity prices and production. The portion of supervision fees netted from production costs was \$0.5 million for the third quarters of 2003 and 2002.

Interest expense on our Senior Notes due 2009, including amortization of debt issuance costs, totaled \$3.3 million in both the third quarter of 2003 and 2002. Interest expense on our Senior Notes due 2012, including amortization of debt issuance costs, totaled \$4.8 million in the third quarter of 2003 and \$4.7 million in the third quarter of 2002. Interest expense on our credit facility, including commitment fees and amortization of debt issuance costs, totaled \$0.3 million in the third quarter of 2003 and \$0.4 million in the same period in 2002. The total interest cost in the third quarter of 2003 was \$8.4 million, of which \$1.7 million was capitalized. The total interest cost in the third quarter of 2002 was \$8.4 million, of which \$1.8 million was capitalized. We capitalize that portion of interest related to our unproved properties.

Net Income. Our net income in the third quarter of 2003 of \$7.1 million was 263% higher and Basic EPS of \$0.26 were 256% higher than our third quarter of 2002 net income of \$1.9 million and Basic EPS of \$0.07. Our Diluted EPS in the third quarter of 2003 of \$0.26 were also 256% higher than our third quarter of 2002 Diluted EPS of \$0.07. These amounts increased in the 2003 period as oil and gas sales increased due to higher commodity prices and our increased production.

RESULTS OF OPERATIONS – Nine Months Ended September 30, 2003 and 2002

Revenues. Our revenues in the first nine months of 2003 increased by 42% to \$155.8 million compared to revenues of \$109.5 million in the same period in 2002, primarily due to increases in oil and gas prices and, to a lesser extent, our increased production.

Oil and gas sales revenues of \$157.8 million in the first nine months of 2003 increased by 55%, or \$56.3 million, from the level of those revenues for the comparable 2002 period. Our net sales volumes of 39.8 Bcfe in the first nine months of 2003 increased by 7%, or 2.6 Bcfe, over net sales volumes in the comparable 2002 period. Average prices received for oil increased to \$29.80 per Bbl in the first nine months of 2003 from \$26.50 per Bbl in the comparable 2002 period. Average gas prices received increased to \$3.46 per Mcf in the

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

first nine months of 2003 from \$2.21 per Mcf in the 2002 period. Average natural gas liquids (Ngl) prices increased to \$17.87 per Bbl in the first nine months of 2003 from \$11.77 per Bbl in the comparable 2002 period. The increase in production during the 2003 period was from our Lake Washington and New Zealand areas. Our domestic Ngl volumes decreased in the first nine months of 2003, as it was more profitable to sell high Btu natural gas than to strip out ethane and other Ngls from the gas stream.

In the first nine months of 2003, our \$56.3 million increase in oil and gas sales resulted from:

- Price variances that had a \$49.2 million favorable impact on sales, of which \$26.8 million was attributable to the 56% increase in average gas prices received and \$22.4 million was attributable to the 37% increase in the average combined oil and Ngl prices received; and
- Volume variances that had a \$7.1 million favorable impact on sales, with \$4.1 million of the increase coming from the 206,000 Bbl increase in oil and Ngl sales volumes, and \$3.0 million of the increase coming from the 1.4 Bcf increase in gas sales volumes.

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

<u>Area</u>	<u>Nine Months Ended September 30,</u>			
	<u>Revenues (In Millions)</u>		<u>Net Sales Volumes (Bcfe)</u>	
	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>
AWP Olmos	\$ 34.6	\$ 24.1	6.4	8.4
Brookeland	12.3	9.2	2.9	3.1
Lake Washington	40.4	12.1	8.3	3.1
Masters Creek	21.3	25.5	4.6	8.0
Other	15.0	11.3	2.8	4.0
Total Domestic	<u>\$ 123.6</u>	<u>\$ 82.2</u>	<u>25.0</u>	<u>26.6</u>
Rimu/Kauri	6.8	2.5	2.0	1.0
TAWN	27.4	16.8	12.8	9.6
Total New Zealand	<u>\$ 34.2</u>	<u>\$ 19.3</u>	<u>14.8</u>	<u>10.6</u>
Total	<u>\$ 157.8</u>	<u>\$ 101.5</u>	<u>39.8</u>	<u>37.2</u>

Our drilling efforts in the first nine months of 2003 have focused on Lake Washington, AWP Olmos and New Zealand. During 2003, our TAWN natural gas production in New Zealand was materially higher than original expectations due to increased natural gas demand in New Zealand and facility modifications implemented by our New Zealand operations. As a result of this increased production, which we believe peaked during the third quarter of 2003, the depletion of our TAWN property during the first nine months of 2003 was at a higher rate than was seen during the comparable 2002 period, and we expect a higher rate of depletion to continue. We also expect to conduct future drilling operations to add new supply volumes and install compression to improve deliverability and recovery of natural gas in the TAWN area.

SWIFT ENERGY COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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The following table provides additional information regarding our oil and gas sales:

	<u>Net Sales Volume</u>				<u>Average Sales Price</u>		
	Oil (MBbl)	Ngl (MBbl)	Gas (Bcf)	Combined (Bcfe)	Oil (Bbl)	Ngl (Bbl)	Gas (Mcf)
<u>2002</u>							
Nine Months Ended September 30:							
Domestic	1,257	1,110	12.4	26.6	\$27.38	\$11.91	\$2.78
New Zealand	342	145	7.6	10.6	\$23.28	\$10.76	\$1.29
Total	<u>1,599</u>	<u>1,255</u>	<u>20.0</u>	<u>37.2</u>	\$26.50	\$11.77	\$2.21
<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>	\$29.80	\$17.87	\$3.46

In March 2002, we received \$7.5 million for our interest in the Samburg project located in western Siberia, Russia as a result of the sale by a third party of its ownership in a Russia joint stock company that owned and operated the field. Although the proceeds from sales of oil and gas properties are generally treated as a reduction of oil and gas property costs, because we had previously charged to expense all \$10.8 million of cumulative costs relating to our Russian activities, this cash payment, net of transaction expenses, resulted in recognition of a \$7.3 million non-recurring gain on asset disposition in the first quarter of 2002. This activity was recorded in "Gain on asset disposition" in the accompanying consolidated statement of income.

During the first nine months of 2003, we recognized net losses of \$2.4 million relating to our hedging activities, as compared to net losses of \$0.2 million in the same 2002 period. This activity is recorded in "Price-risk management and other, net" on the accompanying consolidated statement of income.

Revenues from our oil and gas sales comprised substantially all of net revenues for the first nine months of 2003 and 93% of total revenues for the comparable 2002 period. Natural gas production made up 54% of our production volumes in the first nine months of both 2003 and 2002.

Costs and Expenses. Our expenses in the first nine months of 2003 increased \$21.0 million, or 22%, compared to the same 2002 period expenses. The majority of the increase was due to our increased oil and gas production costs, both domestically and in New Zealand, an increase in depletion expense, both domestically and in New Zealand, and an increase in interest expense due to replacement of our bank borrowings with our Senior Notes due 2012.

Our net general and administrative expense in the first nine months of 2003 increased \$3.2 million, or 43%, from the level of such expenses in the comparable 2002 period. These increases reflect additional costs needed for our increased activities in New Zealand, a reduction in reimbursement from partnerships we managed as almost all of these partnerships have liquidated, an increase in franchise tax expense, and increased costs related to our corporate governance activities and compliance with the Sarbanes-Oxley Act. Our general and administrative expenses per Mcfe produced increased to \$0.27 per Mcfe in the first nine months of 2003 from \$0.20 per Mcfe in the same 2002 period. The portion of supervision fees netted from general and administrative expenses was \$2.2 million for the first nine months of 2003 and \$2.3 million for the same 2002 period.

SWIFT ENERGY COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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Depreciation, depletion, and amortization of our assets, or DD&A, increased \$4.8 million, or 12%, in the first nine months of 2003 from the same 2002 period. Domestically, DD&A decreased \$1.7 million due to decreased production in the same 2003 period, and higher reserve volumes that were added primarily through our Lake Washington activities. In New Zealand, our production increased in the first nine months of 2003 in both the Rimu/Kauri and TAWN areas, which increased DD&A in this period. Our DD&A rate per Mcfe of production was \$1.17 in the first nine months of 2003 and \$1.12 in the same 2002 period, reflecting these variations in per unit cost of reserves additions.

We recorded \$0.6 million of accretion on our asset retirement obligation in the first nine months of 2003 associated with the adoption of SFAS No. 143 implemented on January 1, 2003.

Our production costs increased \$8.8 million in the first nine months of 2003, or 29%, and were \$0.99 and \$0.82 per Mcfe in the first nine months of 2003 and 2002, respectively. Due to the 41% increase in production during the first nine months of 2003, our New Zealand operations contributed \$4.4 million of the cost increase in the period. Domestic severance taxes increased \$4.4 million in the first nine months of 2003, due to higher commodity prices. The portion of supervision fees netted from production costs was \$1.5 million for the first nine months of both 2003 and 2002.

Interest expense on our Senior Notes due 2009, including amortization of debt issuance costs, totaled \$9.9 million in both the first nine months of 2003 and 2002. Interest expense on our Senior Notes due 2012, including amortization of debt issuance costs, totaled \$14.3 million and \$8.7 million in the first nine months of 2003 and 2002, respectively. Interest expense on our credit facility, including commitment fees and amortization of debt issuance costs, totaled \$1.1 million in the first nine months of 2003 and \$3.3 million in the same period in 2002. The total interest cost in the first nine months of 2003 was \$25.3 million, of which \$5.2 million was capitalized. The total interest cost in the first nine months of 2002 was \$21.9 million, of which \$5.3 million was capitalized. We capitalize that portion of interest related to our unproved properties. The increase in interest expense in the first nine months of 2003 was attributed to the replacement of our bank borrowings in April 2002 with the Senior Notes due 2012 that carry a higher interest rate and a longer term.

As discussed in Note 1 to the Consolidated Financial Statements, we implemented SFAS No. 143 effective 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 consolidated statement of income. This statement requires that the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets be recorded 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. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the obligation is either settled for its recorded amount or a gain or loss is incurred upon settlement. This statement requires that a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values be recorded.

Net Income. Our net income in the first nine months of 2003 of \$20.4 million was 138% higher and Basic EPS of \$0.75 were 131% higher than our first nine months of 2002 net income of \$8.6 million and Basic EPS of \$0.33. Our Diluted EPS in the first nine months of 2003 of \$0.74 were also 131% higher than our first nine months of 2002 Diluted EPS of \$0.32. These amounts increased in the same 2003 period as oil and gas sales increased due to higher commodity prices and our increased production.

Related-Party Transactions

We are currently the operator of a limited number of properties owned by the six remaining affiliated limited partnerships and, accordingly, charge these entities operating fees. The operating fees charged to the partnerships were approximately \$0.1 million in the first nine months of 2003 and \$0.3 million in the 2002 period, and are recorded as reductions of general and administrative expense and oil and gas production expense. We also have been reimbursed for direct, administrative, and overhead costs incurred in conducting

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

the business of the limited partnerships, which totaled approximately \$0.4 million and \$0.9 million in the first nine months of 2003 and 2002, respectively. These lower amounts reflect our continued transition away from partnerships.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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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 discussed in Management's Discussion and Analysis, and such volatility is expected to continue.

Our price-risk program permits the utilization of derivative instruments (such as futures, forward and options contracts, and swaps) 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, 2003, we had price floors in place effective through the contract month of December 2003 for natural gas and through November 2003 for crude oil. The natural gas price floors cover notional volumes of 1,050,000 MMBtu, with a weighted average floor price of \$4.75 per MMBtu. The crude oil price floors cover notional volumes of 180,000 barrels of oil, with a weighted average floor price of \$27.58 per barrel. Our hedges in place at September 30, 2003 should cover approximately 25% to 30% of our forecasted fourth quarter 2003 gas production and 15% to 20% of our forecasted fourth quarter 2003 oil production.
- *New Zealand Gas Contracts* – A majority of our 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 fluctuations in volumes delivered 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 Kiwi. Fluctuations in rates between the New Zealand Kiwi and U.S. Dollar may impact our financial results from our New Zealand subsidiaries since we have receivables and liabilities denominated in New Zealand Kiwi.

Interest Rate Risk

Our Senior Notes have a fixed interest rate, so consequently we are not exposed to cash flow risk from market interest rate changes on our Senior Notes. However, there is a risk that market rates will decline and the required interest payments on our Senior Notes may exceed those payments based on the current market rate. At September 30, 2003, we had \$11.9 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 40 basis points and would not have a material adverse effect on our 2003 cash flows based on this same level of borrowing.

CONTROLS AND PROCEDURES

The Company's chief executive officer and chief financial officer have evaluated the Company's disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") as of the end of the period covered by this report. Based on that evaluation, they have concluded that such disclosure controls and procedures are effective, in all material respects, in communicating to them on a timely basis material information relating to the Company required under the Exchange Act to be disclosed in this quarterly report.

There were no significant changes in the Company's internal control over financial reporting that occurred during the Company's last fiscal quarter that have materially affected, or are reasonably likely to materially affect, such control.

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. Changes in Securities and Use of Proceeds - N/A

Item 3. Defaults Upon Senior Securities - N/A

Item 4. Submission of Matters to a Vote of Security Holders – N/A

Item 5. Other Information – N/A

Item 6. Exhibits & Reports on Form 8-K -

(a) Documents filed as part of the report

(3) Exhibits

10.19 Employment Agreement dated as of November 1, 2003 between Swift Energy Company and James P. Mitchell.

12 Swift Energy Company Ratio of Earnings to Fixed Charges.

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.

(b) Reports on Form 8-K filed during the quarter ended September 30, 2003, which are incorporated herein by reference:

On August 6, 2003, the Company filed a Current Report on Form 8-K that reported under Item 7, "Financial Statements, Pro Forma Financial Information and Exhibits" and Item 12, "Results of Operations and Financial Conditions" relating to the press release announcement of second quarter 2003 earnings.

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 14, 2003

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

Date: November 14, 2003

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 of Swift Energy Company;
2. Based on my knowledge, this quarterly 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 quarterly report;
3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of Swift Energy as of, and for, the periods presented in this quarterly report;
4. Swift Energy'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 Swift Energy and we 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 Swift Energy, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;
 - b) evaluated the effectiveness of Swift Energy's disclosure controls and procedures and presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this quarterly report based on such evaluation; and
 - c) disclosed in this quarterly report any changes in Swift Energy Company's internal control over financial reporting that occurred during Swift Energy Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Swift Energy Company's internal control over financial reporting; and
5. Swift Energy's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Swift Energy Company's auditors and the audit committee of Swift Energy Company's board of directors (or persons performing the equivalent functions):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect Swift Energy Company'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 Swift Energy Company's internal control over financial reporting.

Date: November 14, 2003

(original signed by)

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 of Swift Energy Company;
2. Based on my knowledge, this quarterly 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 quarterly report;
3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of Swift Energy as of, and for, the periods presented in this quarterly report;
4. Swift Energy'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 Swift Energy and we 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 Swift Energy, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;
 - b) evaluated the effectiveness of Swift Energy's disclosure controls and procedures and presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this quarterly report based on such evaluation; and
 - c) disclosed in this quarterly report any changes in Swift Energy Company's internal control over financial reporting that occurred during Swift Energy Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Swift Energy Company's internal control over financial reporting; and
5. Swift Energy's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Swift Energy Company's auditors and the audit committee of Swift Energy Company's board of directors (or persons performing the equivalent functions):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect Swift Energy Company'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 Swift Energy Company's internal control over financial reporting.

Date: November 14, 2003

(original signed by)

Alton D. Heckaman, Jr.
Senior Vice President - Finance
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 quarter ended September 30, 2003 (the "Report") of Swift Energy Company ("Swift") as filed with the Securities and Exchange Commission on November 14, 2003, 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 14, 2003

(original signed by)

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

Dated: November 14, 2003

(original signed by)

Terry E. Swift
President and Chief Executive Officer

This certification made in accordance with Section 906 of the Sarbanes-Oxley Act of 2002 is furnished by Swift and accompanies the Quarterly Report on Form 10-Q of Swift for the period ended September 30, 2003. This certification shall not be deemed filed by Swift for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended.