SWIFT ENERGY CO
Form 10-Q
August 05, 2005

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 June 30, 2005

Commission File Number 1-8754

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

TEXAS	74-2073055
(State of Incorporation)	(I.R.S. Employer Identification No.)

16825 Northchase Drive, Suite 400

Houston, Texas 77060
(Address of principal executive offices) (Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities 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 |X| No |_|

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).
Yes |X| 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	28,595,381 Shares
($.01 Par Value)	(Outstanding at July 31, 2005)
(Class of Stock)	

SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2005

INDEX

CONDENSED CONSOLIDATED BALANCE SHEETS
SWIFT ENERGY COMPANY

	June 30, 2005	December
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 27,728,290	$
Accounts receivable –		
Oil and gas sales	46,260,907	3
Joint interest owners	606,591	
Other current assets	15,064,295	1
Total Current Assets	89,660,083	5
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties being amortized	1,581,386,007	1,47
Unproved properties not being amortized	80,994,868	8
	1,662,380,875	1,55
Furniture, Fixtures, and Other Equipment	14,099,878	1
	1,676,480,753	1,57
Less-Accumulated Depreciation, Depletion, and Amortization	(702,299,352)	(64
	974,181,401	92
Other Assets:		
Deferred income taxes	---	
Debt issuance costs	8,598,414	
Restricted assets	1,914,856	
	10,513,270	1
	$ 1,074,354,754	$ 99
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 29,411,912	$ 2
Accrued capital costs	30,243,537	2
Accrued interest	8,506,743	
Undistributed oil and gas revenues	7,840,625	
Total Current Liabilities	76,002,817	6
Long-Term Debt	350,000,000	35
Deferred Income Taxes	97,876,922	7
Asset Retirement Obligation	16,584,569	1
Lease Incentive Obligation	158,724	
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, 29,005,618 and 28,570,632 shares issued, and 28,556,174 and 28,089,764 shares outstanding, respectively	290,056	

Additional paid-in capital	350,179,003	34
Treasury stock held, at cost, 449,444 and 480,868 shares, respectively	(6,445,586)	(
Unearned Compensation	(2,059,168)	(
Retained Earnings	192,095,111	13
Accumulated Other Comprehensive Income (Loss), Net of Taxes	(327,694)	
	533,731,722	47
	$ 1,074,354,754	$ 99

See accompanying notes to condensed consolidated financial statements.

3

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
SWIFT ENERGY COMPANY

	Three Months Ended		Six Mont
	06/30/05	06/30/04	06/30/05
Revenues:			
Oil and gas sales	$ 104,922,400	$ 71,824,789	$ 200,443,733
Price-risk management and other, net	(622,475)	(781,054)	(523,124)
	104,299,925	71,043,735	199,920,609
Costs and Expenses:			
General and administrative, net	4,995,887	4,175,559	9,870,195
Depreciation, depletion and amortization	28,777,631	19,509,056	52,983,009
Accretion of asset retirement obligation	187,495	160,259	374,002
Lease operating costs	11,565,223	10,435,813	22,614,005
Severance and other taxes	10,708,754	6,927,269	19,911,835
Interest expense, net	6,286,894	7,143,389	12,630,903
Debt retirement cost	---	2,691,243	---
	62,521,884	51,042,588	118,383,949
Income Before Income Taxes	41,778,041	20,001,147	81,536,660
Provision for Income Taxes	13,896,383	7,103,220	27,965,850
Net Income	$ 27,881,658	$ 12,897,927	$ 53,570,810

Per Share Amounts

Basic: Net Income	$ 0.98	$ 0.46	$ 1.90
Dilute: Net Income	$ 0.96	$ 0.46	$ 1.86
Weighted Average Shares Outstanding	28,376,518	27,742,444	28,268,733

See accompanying notes to condensed consolidated financial statements.

4

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
SWIFT ENERGY COMPANY

	Common Stock(1)	Additional Paid-In Capital	Treasury Stock	Unearned Compensation	Retai Earni
Balance December 31, 2003	$ 280,111	$334,865,204	$ (7,558,093)	$ ---	$ 70,07
Stock issued for benefit plans (46,150 shares)	---	166,298	661,848	---	
Stock options exercised (509,105 shares)	5,091	4,260,882	---	---	
Tax benefits from exercise of stock options	---	1,956,555	---	---	
Employee stock purchase plan (50,418 shares)	504	502,097	---	---	
Issuance of restricted stock	---	1,785,262	---	(1,785,262)	
Amortization of restricted stock	---	---	---	56,677	
Net income	---	---	---	---	68,45
Other comprehensive income	---	---	---	---	
Total Comprehensive Income					
Balance December 31, 2004	$ 285,706	$343,536,298	$ (6,896,245)	$ (1,728,585)	$138,52
Stock issued for benefit plans (31,424 shares)	---	435,134	450,659	---	
Stock options exercised (403,550 shares)	4,036	3,489,967	---	---	
Tax benefits from exercise of stock options		1,213,728			
Issuance of restricted stock	---	861,522	---	(600,719)	
Employee stock purchase plan (31,436 shares)	314	642,354	---	---	
Amortization of restricted stock	---	---	---	270,136	
Net income	---	---	---	---	53,57
Other Comprehensive Loss	---	---	---	---	
Total Comprehensive Income					

Balance June 30, 2005	$ 290,056	$350,179,003	$ (6,445,586)	$ (2,059,168)	$192,09

(1) $.01 Par Value

See accompanying notes to condensed consolidated financial statements.

5

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
SWIFT ENERGY COMPANY

	Period Ended June 30,	
	2005	2
Cash Flows From Operating Activities:		
Net income	$ 53,570,810	$ 2
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation, depletion, and amortization	52,983,009	3
Accretion of asset retirement obligation	374,002	
Deferred income taxes	27,565,850	1
Debt retirement cost	---	
Other	117,924	
Change in assets and liabilities -		
Increase in accounts receivable	(4,738,848)	(
Increase in accounts payable and accrued liabilities	113,433	
Decrease in accrued interest	(702,449)	(
Net Cash Provided by Operating Activities	129,283,731	7
Cash Flows From Investing Activities:		
Additions to property and equipment	(101,766,582)	(8
Proceeds from the sale of property and equipment	2,339,634	
Net cash distributed as operator of oil and gas properties	(3,840,937)	(
Net cash received as operator of partnerships and joint ventures	243,286	
Other	50,105	
Net Cash Used in Investing Activities	(102,974,494)	(9
Cash Flows From Financing Activities:		
Proceeds from long-term debt	---	15
Payments of long-term debt	---	(3
Net payments of bank borrowings	(7,500,000)	(1

Net proceeds from issuances of common stock	3,998,935	
Payments of debt retirement costs	---	(
Payments of debt issuance costs	---	(
Net Cash Provided by (Used in) Financing Activities	(3,501,065)	9
Net Increase in Cash and Cash Equivalents	22,808,172	8
Cash and Cash Equivalents at Beginning of Period	4,920,118	
Cash and Cash Equivalents at End of Period	$ 27,728,290	$ 8
Supplemental Disclosures of Cash Flow Information:		
Cash Paid During Period for Interest, Net of Amounts Capitalized	$ 12,798,576	$ 1
Cash Paid During Period for Income Taxes	$ 400,000	$

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. 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

Property and Equipment

We follow the "full-cost" method of accounting for oil and gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and gas reserves are capitalized.

Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the six months ended June 30, 2005 and 2004, such internal costs capitalized totaled $8.8 million and $6.2 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the six months ended June 30, 2005 and 2004, capitalized interest on unproved properties totaled $3.5 million, and $3.2 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 ("DD&A") of oil and gas properties by the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties--including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties--by an overall rate determined by dividing the physical units of oil and gas produced during the period by the total estimated units of proved oil and gas reserves at the beginning of the period. This calculation is done on a country-by-country basis, and the period over which we will amortize these properties is dependent on our production from these properties in future years. Furniture, fixtures, and other equipment, recorded at cost, are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between three and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

Geological and geophysical ("G&G") costs incurred on developed properties are recorded in "Proved Properties" and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in "Unproved properties" and evaluated as part of the total capitalized costs associated with a prospect.

The cost of unproved properties not being amortized is assessed quarterly, on a country-by-country basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, foreign currency exchange rates, the political stability in the countries in which we have an investment, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized. To the extent costs accumulate in countries where there are no proved reserves, any costs determined by management to be impaired are charged to expense.

Full-Cost Ceiling Test

At the end of each quarterly reporting period, the unamortized cost of oil and gas properties, including gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability is limited to the sum of the estimated future net revenues from proved properties, excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects ("Ceiling Test"). Our hedges at June 30, 2005 consisted of natural gas and crude oil price floors with strike prices lower than the period end price and thus did not materially affect prices used in this calculation. This calculation is done on a country-by-country basis.

The calculation of the Ceiling Test and provision for DD&A is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered. Our reserves estimates are prepared in accordance with Securites and Exhange Commission guidelines; and, are audited on an annual basis at year-end by a firm of independent petroleum engineers in accordance with standards approved by the Board of Directors of the Society of Petroleum Engineers.

Given the volatility of oil and gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that non-cash write-downs of oil and gas properties could occur in the future.

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Swift Energy Company and 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 oil and natural gas reserves in New Zealand. Our undivided interests in gas processing plants, and investments in six oil and gas limited partnerships where we are the general partner are accounted for using the proportionate consolidation method, whereby our proportionate share of each entity's assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying consolidated financial statements.

Revenue Recognition

Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. Processing costs for natural gas and natural gas liquids ("NGLs") that are paid in-kind are deducted from revenues. The Company uses the entitlement method of accounting in which the Company recognizes its ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying balance sheet. Natural gas balancing receivables are reported in "Other current assets" on the accompanying balance sheet when our ownership share of production exceeds sales. As of June 30, 2005, we did not have any material natural gas imbalances.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY

Accounts Receivable

Included in the "Accounts receivable" balance, which totaled $46.9 million and $39.0 million at June 30, 2005 and December 31, 2004, respectively, on the accompanying balance sheets, are approximately $2.3 million of receivables related to hydrocarbon volumes produced from 2001 and 2002 that have been disputed since early 2003. As a result of the dispute, we did not record a receivable with regard to any 2003 disputed volumes and our contract governing these sales expired in 2003. Based on settlement discussions, we settled our claim with this counter-party in July 2005 by receiving a cash payment for less than our gross receivable. Accordingly, in the second quarter of 2005, we increased our reserve for this claim by approximately $0.6 million, which is recorded in "Price-risk management and other, net" on the accompanying statements of income.

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 June 30, 2005 and December 31, 2004, we had an allowance for doubtful accounts of $1.0 million and $0.5 million, respectively. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying balance sheets.

Inventories

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

	Balance at June 30, 2005 (000's)	Balance at December 31, 2004 (000's)
Materials, Supplies and Tubulars	$ 10,759	$ 6,417
Crude Oil	829	770
Total	$ 11,588	$ 7,187

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States (GAAP) requires us to make estimates and assumptions that affect the reported amount of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there from,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,
- the estimated future cost and timing of asset retirement obligations, and
- estimates made in our income tax calculations.

While we are not aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY

Income Taxes

Under SFAS No. 109, "Accounting for Income Taxes," deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws. The effective tax rates for both the first six months of 2005 and 2004 were 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 and corrections to the New Zealand tax basis calculations. In the first six months of 2005, these amounts were partially offset by higher deferred state income taxes. The first six months of 2004 included favorable corrections to tax basis amounts discovered while preparing the prior year's tax returns. The tax laws in the jurisdictions we operate in are continuously changing and professional judgments regarding such laws can differ. The Company continues to evaluate the impact of the recently enacted American Jobs Creation Act of 2004. We do not believe this act will have a material impact in the near-term on our financial position or results of operations.

Accounts Payable and Accrued Liabilities

Included in "Accounts payable and accrued liabilities," on the accompanying balance sheets, at June 30, 2005 and December 31, 2004 are liabilities of approximately $5.4 million and $6.9 million, respectively, representing the amount by which checks issued, but not presented to the Company's banks for collection, exceeded balances in the applicable disbursement bank accounts.

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

We follow the provisions of SFAS No. 130, "Reporting Comprehensive Income," which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At June 30, 2005, we recorded $0.3 million, net of taxes of $0.2 million, of derivative losses in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying balance sheet. The components of accumulated other comprehensive income (loss) and related tax effects for the period ending June 30, 2005 were as follows:

	Gross Value	Tax Effect	T
Other comprehensive income at December 31, 2004	$ 710,828	$ (260,163)	$
Change in fair value of cash flow hedges	(797,939)	292,045	
Effect of cash flow hedges settled during the period	(429,756)	157,291	
Other comprehensive loss at June 30, 2005	$ (516,867)	$ 189,173	$

Total comprehensive income was $28.1 million and $13.0 million for the second quarters of 2005 and 2004, respectively. Total comprehensive income was $52.8 million and $27.6 million for the first six months of 2005 and 2004, respectively.

Stock Based Compensation

We account for two stock-based compensation plans under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. We issued restricted stock to employees for the first time in the fourth quarter of 2004, and then to directors in the second quarter of 2005, and for the period ended June 30, 2005 we recorded expense related to these shares of $0.3 million in "General and administrative, net" on the accompanying statements of income. No stock-based employee compensation cost is reflected in net income for employee stock options, as all options granted under our plan 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, as 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:

		Three Months Ended
		2005
Net Income:	As Reported	$27,881,658
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(1,113,938)
	Pro Forma	$26,767,720
Basic EPS:	As Reported	$.98
	Pro Forma	$.94

Diluted EPS:	As Reported	$.96
	Pro Forma	$.92

		Six Months Ended J
		2005
Net Income:	As Reported	$53,570,810
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(1,973,089)
	Pro Forma	$51,597,721
Basic EPS:	As Reported	$1.90
	Pro Forma	$1.83
Diluted EPS:	As Reported	$1.86
	Pro Forma	$1.79

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. We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

Price-Risk Management Activities

The Company follows SFAS No. 133, which requires that changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The statement also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the balance sheet as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the income statements and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Changes in the fair value of derivatives that do not meet the criteria for hedge accounting, and the ineffective portion of the hedge, are recognized currently in income.

We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. During the second quarters of 2005 and 2004, we recognized net losses of $0.4 million and $0.5 million, respectively, relating to our derivative activities. During the first six months of 2005 and 2004, we recognized net losses of $0.5 million and $1.1 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. At June 30, 2005, the Company had recorded $0.3 million, net of taxes of $0.2 million, of derivative losses in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for the first six months of 2005 and 2004 was not material. We expect to reclassify all amounts currently held in "Accumulated other comprehensive income (loss), net of income tax" into the statement of income within the next six months when the forecasted sale of hedged production occurs.

At June 30, 2005, we had in place price floors in effect for July 2005 through the December 2005 contract month for natural gas, that cover a portion of our domestic natural gas production for July 2005 to December 2005. The natural gas price floors cover notional volumes of 2,300,000 MMBtu, with a weighted average floor price of $5.71 per MMBtu. Our natural gas price floors in place at June 30, 2005 are expected to cover approximately 30% to 35% of our estimated domestic natural gas production from July 2005 to December 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 production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive income (loss), net of income tax." When the hedged transactions are recorded upon the actual sale of oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive income (loss), net of income tax" and recorded in "Price-risk management and other, net" on the accompanying statement of income. The fair value of our derivatives is computed using the Black-Scholes option pricing model and is periodically verified against quotes from brokers. The fair value of these instruments at June 30, 2005, was less than $0.1 million and is recognized on the accompanying balance sheet in "Other current assets."

Supervision Fees

Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees are recorded as a reduction to general and administrative, net based on our estimate of the costs incurred to operate the wells. The total amount of supervision fees charged to the wells we operate was $3.8 million and $2.5 million in the first six months of 2005 and 2004, respectively.

Asset Retirement Obligation

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, "Accounting for Asset Retirement Obligations." The statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. The liability is discounted from the year the well is expected to deplete. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. This standard requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values. Based on our experience and analysis of the oil and gas services industry, we have not factored a market risk premium into our asset retirement obligation. SFAS No. 143 was adopted by us effective January 1, 2003. The following provides a roll-forward of our asset retirement obligation:

	2005	
Asset Retirement Obligation recorded as of January 1	$ 17,639,136	$
Accretion expense for the six months ended June 30	374,002	
Liabilities incurred for new wells and facilities construction	54,622	
Reductions due to sold, or plugged and abandoned wells	(277,604)	
Decrease due to currency exchange rate fluctuations	(19,087)	
Asset Retirement Obligation as of June 30	$ 17,771,069	$

At June 30, 2005 and December 31, 2004, approximately $1.2 million and $0.5 million, respectively, of our asset retirement obligation is classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying balance sheets.

New Accounting Pronouncements

In September and November 2004, and March 2005, the EITF discussed a proposed framework for addressing when a limited partnership should be consolidated by its general partner, EITF Issue 04-5. The proposed framework presumes that a sole general partner in a limited partnership controls the limited partnership, and therefore should consolidate the limited partnership. The presumption of control can be overcome if the limited partners have (a) the substantive ability to remove the sole general partner or otherwise dissolve the limited partnership or (b) substantive participating rights. The EITF reached a tentative conclusion on the circumstances in which either kick-out rights or participating rights would be considered substantive and preclude consolidation by the general partner and what limited partner's rights would be considered participating rights that would preclude consolidation by the general partner. The EITF tentatively concluded that for kick-out rights to be considered substantive, the conditions specified in paragraph B20 of FIN 46R should be met. With regard to the definition of participating rights that would preclude consolidation by the general partner, the EITF concluded that the definition of those rights should be consistent with those in EITF Issue 96-16. The EITF also reached a tentative conclusion on the transition for Issue 04-05. The FASB ratified the EITF consensus at the June 2005 EITF meeting. We do not believe this EITF will have a material impact on our consolidated financial statements because we believe our limited partners have substantive kick-out rights under paragraph B20 of FIN 46R.

In December 2004, the FASB issued SFAS No. 123R, Share-Based Payment. SFAS No. 123R is a revision of SFAS No. 123, Accounting for Stock-Based Compensation, and supercedes APB Opinion No. 25, Accounting for Stock Issued to Employees, and amends SFAS No. 95, Statement of Cash Flows. SFAS No. 123R requires all employee share-based payments, including grants of employee stock options, to be recognized in the financial statements based on their fair values. SFAS No. 123 discontinues the ability to account for these equity instruments under the intrinsic value method as described in APB Opinion No. 25. SFAS No. 123R requires the use of an option pricing model for estimating fair value, which is amortized to expense over the service periods. The requirements of SFAS No. 123R are effective for fiscal periods beginning after June 15, 2005. SFAS No. 123R permits public companies to adopt its requirements using one of two methods:

- A "modified prospective" method in which compensation cost is recognized beginning with the effective date based on the requirements of SFAS No. 123R for all share-based payments granted after the effective date and based on the requirements of SFAS No. 123 for all awards granted to employees prior to the adoption date of SFAS No. 123R that remain unvested on the adoption date.

- A "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS No. 123 for purposes of pro forma disclosures.

In April 2005, the SEC issued a release announcing that it would provide for a phased-in implementation process for SFAS No. 123R. As a result, our required date to adopt SFAS No. 123R is now January 1, 2006. Also in April 2005, the SEC issued Staff Accounting Bulleting No.

107, Share-Based Payment, which provides guidance on the implementation of SFAS No. 123R. SAB No. 107 provides guidance on valuing options, estimating volatility and expected terms of the option awards, and discusses the SEC's views on share-based payment transactions with non-employees, the capitalization of compensation cost and accounting for income tax effects of share-based payment arrangements upon adoption of SFAS No. 123R.

We have elected to adopt the provisions of SFAS No. 123R on January 1, 2006 using the modified prospective method. As permitted by Statement 123, the Company currently accounts for share-based payments to employees using APB Opinion No. 25's intrinsic value method and, as such, generally recognizes no compensation cost for employee stock options. Accordingly, the adoption of Statement No. 123R's fair value method is expected to have a significant impact on our results of operations. However, it will have no impact on our overall financial position. We currently use the Black-Scholes formula to estimate the value of stock options granted to employees and expect to continue to use this acceptable option valuation model upon the required adoption of SFAS No. 123R. The significance of the impact of adoption will depend on levels of outstanding unvested share-based payments on the date of adoption and share-based payments granted in the future. However, had we adopted Statement No. 123R in prior periods, the impact of that standard would have approximated the impact of Statement No. 123 as described in the disclosure of pro forma net income and earnings per share under "Stock Based Compensation" above.

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

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

In July 2005, the FASB issued an exposure draft "Accounting for Uncertain Tax Positions, a proposed interpretation of FASB Statement No. 109." The proposed interpretation would apply to all open tax positions under FASB No. 109. The conclusions in this interpretation include: initial recognition of tax benefits, recognition and de-recognition of tax positions, measurement of tax benefits and classifications of tax liabilities. The comment period on this exposure draft ends in September 2005, and we are currently assessing the impact, if any, that this interpretation would have on our financial position and results of operations. The proposal enactment date would require application effective December 31, 2005.

(3) Earnings Per Share

Basic earnings per share ("Basic EPS") have been computed using the weighted average number of common shares outstanding during the respective periods. Diluted earnings per share ("Diluted EPS") for all periods also assumes, as of the beginning of the period, exercise of stock options and restricted stock grants to employees using the treasury stock method. Certain of our stock options, that could potentially dilute Basic EPS in the future, were anti-dilutive for the three-month and six-month periods ended June 30, 2005 and 2004, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the three-month and six-month periods ended June 30, 2005 and 2004:

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY

	Three Months Ended June 30,				
	2005			2004	
	Net Income	Shares	Per Share Amount	Net Income	Shar
Basic EPS:					
Net Income and Share Amounts	$ 27,881,658	28,376,518	$ 0.98	$ 12,897,927	27,742
Dilutive Securities:					
Restricted Stock	---	30,579		---	
Stock Options	---	601,835		---	555
Diluted EPS:					
Net Income and Assumed Share Conversions	$ 27,881,658	29,008,932	$ 0.96	$ 12,897,927	28,297

	Six Months Ended June 30,				
	2005			2004	
	Net Income	Shares	Per Share Amount	Net Income	Shar
Basic EPS:					
Net Income and Share Amounts	$ 53,570,810	28,268,733	$ 1.90	$ 27,485,781	27,647
Dilutive Securities:					
Restricted Stock	---	25,781		---	
Stock Options	---	554,986		---	504
Diluted EPS:					
Net Income and Assumed Share Conversions	$ 53,570,810	28,849,500	$ 1.86	$ 27,485,781	28,152

Options to purchase approximately 2.6 million shares at an average exercise price of $20.10 were outstanding at June 30, 2005, while options to purchase 2.9 million shares at an average exercise price of $17.37 were outstanding at June 30, 2004. Approximately 0.3 million and 0.9 million options to purchase shares were not included in the computation of Diluted EPS for the three-month periods ended June 30, 2005 and 2004, respectively, and approximately 0.7 million and 1.0 million options to purchase shares were not included in the computation of Diluted EPS for the six-month periods ended June 30, 2005 and 2004, respectively, because these options were antidilutive in that the option price was greater than the average closing market price for the common shares during those periods. Restricted stock grants to consultants of 15,000 shares, which were issued in the second half of 2004, were not included in the computation of Diluted EPS for the three-month and six-month periods ended June 30, 2005, as performance conditions surrounding the vesting of these shares had not occurred.

(4) Long-Term Debt

Our long-term debt, including the current portion, as of June 30, 2005 and December 31, 2004, was as follows (in thousands):

	June 30, 2005	December 3 2004
Bank Borrowings	$ ---	$
7-5/8% senior notes due 2011	150,000	15
9-3/8% senior subordinated notes due 2012	200,000	20
Long-Term Debt	$ 350,000	$ 35

Bank Borrowings

At June 30, 2005, we had no outstanding borrowings under our $400.0 million credit facility with a syndicate of ten banks that has a borrowing base of $250.0 million and expires in October 2008. At December 31, 2004, we had $7.5 million in outstanding borrowings under our credit facility. The interest rate is either (a) the lead bank's prime rate (6.25% at June 30, 2005), or (b) the adjusted London Interbank Offered Rate ("LIBOR") plus the applicable margin depending on the level of outstanding debt. The applicable margin is based on the ratio of the outstanding balance to the last calculated borrowing base. In June 2004, we renewed this credit facility, increasing the facility to $400 million from $300 million and extending its expiration to October 1, 2008 from October 1, 2005. The other terms of the credit facility, such as the borrowing base amount and commitment amount, stayed largely the same. The covenants related to this credit facility changed somewhat with the extension of the facility and are discussed below. We incurred $0.4 million of debt issuance costs related to the renewal of this facility in 2004, which is included in "Debt issuance costs" on the accompanying balance sheets and will be amortized to interest expense over the life of the facility.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $5.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $15.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt or repurchasing our 7-5/8% senior notes due 2011 or 9-3/8% senior subordinated notes due 2012. Since inception, no cash dividends have been declared on our common stock. We are currently in compliance with the provisions of this agreement. The credit facility is secured by our domestic oil and gas properties. We have also pledged 65% of the stock in our two New Zealand subsidiaries as collateral for this credit facility. The borrowing base is re-determined at least every six months and was reconfirmed by our bank group at $250.0 million effective May 1, 2005. At our request, the commitment amount with our bank group was reduced to $150.0 million effective May 9, 2003, and continues at this amount. Under the terms of the credit facility, we can increase this commitment amount back to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. The next scheduled borrowing base review is in November 2005.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $0.2 million and $0.5 million for the three-months ended June 30, 2005 and 2004, respectively, and $0.6 million and $0.9 million for the six-months ended June 30, 2005 and 2004, respectively. The amount of commitment fees included in interest expense, net was $0.1 million for both the three-months ended June 30, 2005 and 2004, respectively, and $0.3 million and $0.2 million for the six-months ended June 30, 2005 and 2004, respectively.

Senior Notes Due 2011

These notes consist of $150.0 million of 7-5/8% senior notes due 2011, which were issued on June 23, 2004 at 100% of the principal amount and will mature on July 15, 2011. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and rank senior to all of our existing and future subordinated indebtedness. Interest on these notes is payable semi-annually on January 15 and July 15, and commenced on January 15, 2005. On or after July 15, 2008, we may redeem some or all of the notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.813% of principal, declining to 100% in 2010 and thereafter. In addition, prior to July 15, 2007, we may redeem up to 35% of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.625% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $3.9 million of debt issuance costs related to these notes, which is included in "Debt issuance costs" on the accompanying balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. Upon certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes

include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled $3.0 million and $0.2 million for the three-months ended June 30, 2005 and 2004, respectively, and $5.9 million and $0.2 million for the six-months ended June 30, 2005 and 2004, respectively.

Senior Subordinated Notes Due 2012

These notes consist of $200.0 million of 9-3/8% senior subordinated notes due May 2012, which were issued on April 16, 2002, and will mature on May 1, 2012. The notes are unsecured senior subordinated obligations and are subordinated in right of payment to all our existing and future senior debt, including our bank credit facility and 7-5/8% senior notes. Interest on these notes is payable semiannually on May 1 and November 1, and commenced on November 1, 2002. On or after May 1, 2007, we may redeem these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.688% of principal, declining to 100% in 2010. In addition, prior to May 1, 2005, we could have redeemed up to 33.33% of these notes with the net proceeds of qualified offerings of our equity at 109.375% of the principal amount of these notes, plus accrued and unpaid interest. Upon certain changes in control of Swift Energy, each holder of these notes will have the right to require us to repurchase the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these subordinated notes.

Interest expense on the 9-3/8% senior subordinated notes due 2012, including amortization of debt issuance costs totaled $4.8 million for both the three-months ended June 30, 2005 and 2004, and $9.6 million for both the six-months ended June 30, 2005 and 2004.

Other

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

We have capitalized interest on our unproved properties in the amount of $1.7 million and $1.6 million for the three-months ended June 30, 2005 and 2004, respectively, and $3.5 million and $3.2 million for the six-months ended June 30, 2005.

(5) Foreign Activities

As of June 30, 2005, our gross capitalized oil and gas property costs in New Zealand totaled approximately $263.1 million. Approximately $228.9 million has been included in the "Proved properties" portion of our oil and gas properties, while $34.2 million is included as "Unproved properties." Our functional currency in New Zealand is the U.S. Dollar. Net assets of our New Zealand operations total $228.7 million at June 30, 2005. In April 2005, Swift Energy New Zealand ("SENZ") was awarded petroleum mining permit ("PMP") 38155 and petroleum exploration permit ("PEP") 38495 by the New Zealand Government. PMP 38155 is for the development of our Kauri Sand and Manutahi Sand discoveries and covers 8,708 acres and allows us to fully develop our Kauri area for a primary term of 30 years. Following the award of PEP 38495, SENZ initiated a farm-in agreement with Mighty River Power ("MRP"), whereby SENZ agreed to transfer a 50% interest in the permit to MRP in return for MRP funding various seismic operations during 2005 and 2006. PEP 38495 is located offshore in the southern portion of the basin to the south and west of our PEP 38719 and encompasses approximately 600 square miles.

(6) Acquisitions and Dispositions

In late December 2004, we acquired interests in two fields in South Louisiana, the Bay de Chene and Cote Blanche Island fields. We paid approximately $27.7 million in cash for these interests. After taking into account internal acquisition costs of $2.8 million, our total cost was $30.5 million. We allocated $27.8 million of the acquisition price to "Proved properties," and $5.1 million to "Unproved properties." We also recorded $0.5 million to "Restricted assets," and recorded a liability of $2.9 million to "Asset retirement obligation" on our accompanying balance sheet. This acquisition was accounted for

by the purchase method of accounting. We made this acquisition to increase our exploration and development opportunities in South Louisiana. The revenues and expenses from these properties have been included in our accompanying statements of income from the date of acquisition forward, however, given the acquisition was in late December 2004, these amounts were immaterial for 2004.

(7) Segment Information

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

	Three Months Ended June 30,				
	2005			20	
	Domestic	New Zealand	Total	Domestic	N Zeal
Oil and gas sales	$ 89,931,241	$ 14,991,159	$ 104,922,400	$ 59,755,056	$12,0
Costs and Expenses:					
Depreciation, depletion and amortization	22,558,462	6,219,169	28,777,631	14,903,238	4,6
Accretion of asset retirement obligation	154,166	33,329	187,495	119,699	
Lease operating costs	8,503,723	3,061,500	11,565,223	7,935,048	2,5
Severance and other taxes	9,728,291	980,463	10,708,754	6,062,585	8
Income from oil and gas operations	$ 48,986,599	$ 4,696,698	$ 53,683,297	$ 30,734,486	$ 4,0
Price-risk management and other, net			(622,475)		
General and administrative, net			4,995,887		
Interest expense, net			6,286,894		
Debt retirement cost			---		
Income Before Income Taxes			$ 41,778,041		

	Six Months Ended June 30,				
	2005			20	
	Domestic	New Zealand	Total	Domestic	Ne Zeal
Oil and gas sales	$ 166,707,010	$33,736,723	$ 200,443,733	$ 114,421,220	$23,3
Costs and Expenses:					
Depreciation, depletion and amortization	40,232,160	12,750,849	52,983,009	29,421,187	8,3
Accretion of asset retirement obligation	308,023	65,979	374,002	250,247	
Lease operating costs	16,747,940	5,866,065	22,614,005	14,854,330	5,2
Severance and other taxes	17,758,977	2,152,858	19,911,835	11,481,465	1,6
Income from oil and gas operations	$ 91,659,910	$ 12,900,972	$ 104,560,882	$ 58,413,991	$ 7,9
Price-risk management and other, net			(523,124)		
General and administrative,					

net			9,870,195		
Interest expense, net			12,630,903		
Debt retirement cost			---		
Income Before Income Taxes			$ 81,536,660		
Total Assets	$ 845,685,920	$228,668,834	$1,074,354,754	$ 784,300,416	$201,

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 and our Form 10-K for the year ended December 31, 2004. 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 second quarter of 2005, our revenues were $104 million, a 47% increase, and our production was 15.9 Bcfe, a 12% increase, in both cases as compared to second quarter 2004 results. For the first six months of 2005, we had revenues of $199.9 million and production of 31.4 Bcfe, which is a 47% increase in revenues and a 10% increase in production over first half of 2004 results. This performance constitutes a record quarter and record six-month period for Swift Energy. Our revenues for the first half of 2005 were supported by record high oil and gas prices in the industry, while at the same time, our production increased to a historical high for the Company. Our efforts and capital throughout the first half of 2005 remained focused on infrastructure improvements, increased production, and the development of long-lived reserves through exploration and exploitation activities primarily in southern Louisiana, South Texas and New Zealand. We expect to continue this focus throughout 2005.

Our overall costs and expenses have increased, and we expect costs and expenses to continue to increase throughout 2005. The primary increase in these costs and expenses is due to increased depreciation, depletion and amortization expense as a result of increased estimates for future development costs and additional capital expenditures during the year. The other primary factor for our increased costs and expenses is due to increased production in Lake Washington along with higher severance taxes due to increased revenues. Higher severance taxes are driven by higher production and revenue. We've also seen an increase in our general and administrative expenses due to an increased workforce, but our lease operating costs were less than originally anticipated due to lower than expected chemical, repair and maintenance costs as well as no significant work-over activity.

Our financial position remains strong and flexible, allowing us to take advantage of future opportunities in organic growth through drilling or strategic growth through acquisitions. Our financial ratios have also improved recently, our debt to PV-10 ratio decreased to 13% at June 30, 2005 compared to 18% at December 31, 2004, due to higher crude oil and natural gas prices and a slight decrease in our total debt. Higher commodity prices have increased our PV-10 value. Our debt to capitalization ratio was 40% at June 30, 2005 compared to 43% at year-end 2004, as debt levels decreased slightly in 2005 and retained earnings increased as a result of the current period profit.

There are a number of factors that support our belief that Swift Energy's performance for the second half of 2005 will be strong as well. We believe that strong commodity prices will continue over the foreseeable future, based in part on forward-strip pricing. The capacity increase of the facilities in Lake Washington is on schedule to be completed late in the third quarter of 2005, as planned. Our 3-D seismic data study of southern Louisiana has yielded its first exploration success, although further delineation is planned, and an apparent Palau discovery in New Zealand has early results that are encouraging, although we remain cautious as the well needs to be completed and tested. Significant work-over activity is expected to take place in the second half of 2005, particularly in the Bay de Chene and Cote Blanche Island fields in southern Louisiana. Our diversified drilling portfolio positions us for higher impact exploration drilling as well as expanded exploitation efforts in both the last half of 2005 and into 2006.

Results of Operations - Three Months Ended June 30, 2005 and 2004

Revenues. Our revenues in the second quarter of 2005 increased by 47% compared to revenues in the same period in 2004, due primarily to an increase in commodity prices and our overall production volumes. Our production increase was primarily a result of increased crude oil production from our Lake Washington area and, to a lesser extent, the Rimu/Kauri area. Revenues from our oil and gas sales comprised substantially all of our net revenues for the second quarter of both 2005 and 2004. In the second quarter of 2005, oil production made up 54% of total production, natural gas made up 38%, and NGL represented 8%. In the second quarter of 2004, oil production made up 48% of total production, natural gas made up 41%,

and NGL represented 11%. The increase in the percentage of our total production from oil is because production from Lake Washington is almost entirely crude oil, production from this area has increased significantly as a result of our continued development in the field.

Our second quarter of 2005 weighted average prices increased 31%

to $6.60 per Mcfe from $5.04 in the second quarter of 2004, with per barrel oil prices appreciating 35% to $50.24 from $37.24 during the same period in 2004, per Mcfe natural gas prices increasing 12% to $4.67 from $4.19, and per barrel NGL prices rose 22% to $22.95 from $18.84.

The following table sets forth our revenues from oil and gas sales and the volumes underlying those sales from our core areas for the three months ended June 30, 2005 and 2004, illustrating the changes between the two periods:

	Three Months Ended June 30,		
Area	Oil and Gas Sales (In Millions)		Net Oil and Gas Sales V
	2005	2004	2005
AWP Olmos	$ 13.0	$ 12.5	1.9
Brookeland	4.1	4.7	0.7
Lake Washington	62.1	32.8	7.8
Masters Creek	4.4	5.4	0.7
Other	6.3	4.4	0.8
Total Domestic	$ 89.9	$ 59.8	11.9
Rimu/Kauri	9.2	5.2	1.9
TAWN	5.8	6.8	2.1
Total New Zealand	$ 15.0	$ 12.0	4.0
Total	$ 104.9	$ 71.8	15.9

The following table breaks down our sales volumes by commodity and provides average sales prices for each commodity for the quarters ending June 30, 2005 and 2004:

	Sales Volume				Average	
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (Bcfe)	Oil (Bbl)	NG (Bb
2005						
Three Months Ended June 30:						
Domestic	1,339	118	3.2	11.9	$50.21	$25
New Zealand	87	91	2.9	4.0	$50.82	$19
Total	1,426	209	6.1	15.9	$50.24	$22
2004						
Three Months Ended June 30:						

Domestic	1,021	179	3.0	10.2	$37.22	$19
New Zealand	122	90	2.8	4.1	$37.37	$17
Total	1,143	269	5.8	14.3	$37.24	$18

In the second quarter of 2005, our $33.1 million increase in oil, NGL, and natural gas sales over the same period in 2004 resulted from:

- Price variances that had a $22.4 million favorable impact on sales, of which $18.6 million was attributable to the 35% increase in average oil prices received, $2.9 million was attributable to the 12% increase in average gas prices received, and $0.9 million was attributable to the 22% increase in average NGL prices received; and

- Volume variances that had a $10.7 million favorable impact on sales, with $10.5 million of increases coming from the 284,000 Bbl increase in oil sales volumes, $1.3 million of increases due to the 0.3 Bcf increase in gas sales volumes, partially offset by a $1.1 million decrease attributable to the 60,000 Bbl decrease in NGL sales volumes.

Costs and Expenses. Our expenses in the second quarter of 2005 increased $11.5 million, or 22%, compared to expenses in the same period of 2004. The increase was mainly due to a $9.3 million increase in DD&A and a $3.8 million increase in severance and other taxes, both of which are primarily due to increased production volumes and high oil and gas prices in the second quarter of 2005. These cost increases in the second quarter of 2005 were partially offset by debt retirement costs that were incurred in the second quarter of 2004, which totaled $2.7 million.

Our second quarter 2005 general and administrative expenses, net, increased $0.8 million, or 20%, from the level of such expenses in the same 2004 period. This increase was primarily due to an increase in workforce, resulting in increased salaries and benefits, and due to the continued costs of compliance initiatives related to the Sarbanes-Oxley Act. Our net general and administrative expenses per Mcfe produced increased to $0.31 per Mcfe in the second quarter of 2005 from $0.29 per Mcfe in the same 2004 period. For the second quarters of 2005 and 2004, our capitalized general and administrative costs totaled $4.7 million and $3.3 million, respectively. The portion of supervision fees recorded as a reduction to general and administrative expenses was $2.1 million for the second quarter of 2005 and $1.2 million for the 2004 period.

DD&A increased $9.3 million, or 48%, in the second quarter of 2005 from the level of those expenses in the same period of 2004.

Domestically, DD&A increased $7.7 million in the second quarter of 2005 predominantly due to increases in our depletable oil and gas property base including future development costs, higher production in the 2005 period and, to a lesser extent, lower reserve volumes than in the same 2004 period. In New Zealand, DD&A increased by $1.6 million in the second quarter of 2005 due to increases in the depletable oil and gas property base and lower reserve volumes than in the same 2004 period. Our DD&A rate per Mcfe of production was $1.81 and $1.37 in the second quarters of 2005 and 2004, respectively.

We recorded $0.2 million of accretions to our asset retirement obligation in both the second quarters of 2005 and 2004.

Our lease operating costs per Mcfe produced were $0.73 in both the second quarter of 2005 and 2004. Our second quarter 2005 level of lease operating costs was better than anticipated due to lower than expected chemical, repair and maintenance costs, as well as no significant domestic work-over activity taking place in the quarter. Our lease operating costs in the second quarter of 2005 increased $1.1 million, or 11%, over the level of such expenses in the same 2004 period. Approximately $0.6 of the increase was related to our domestic operations, which increased primarily due to higher production from our Lake Washington area. Our lease operating costs in New Zealand increased in the second quarter of 2005 by $0.5 million due to higher plant operating expenses and an increase in the New Zealand dollar exchange rate.

In the second quarter of 2005, severance and other taxes increased $3.8 million, or 55%, over levels in the second quarter of 2004. The increase was due primarily to higher commodity prices and increased Lake Washington and, to a lesser extent, Rimu/Kauri production in the period. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than in the other states where we have production. As our percentage of oil production in Louisiana increases, the overall percentage of severance costs to sales also will increase. Severance and other taxes, as a percentage of oil and gas sales, were approximately 10.2% and 9.6% in the second quarters of 2005 and 2004, respectively.

Interest expense on our 7-5/8% senior notes due 2011 issued in June 2004, including amortization of debt issuance costs, totaled $3.0 million in the second quarter of 2005, and $0.2 million in the same period in 2004. Interest expense on our 9-3/8% senior subordinated notes due 2012 issued in April 2002, including amortization of debt issuance costs, totaled $4.8 million in both the second quarter of 2005 and 2004. Interest expense on our 10-1/4% senior subordinated notes issued in August 1999 and retired in 2004, including amortization of debt issuance costs, totaled $3.3 million in the second quarter of 2004. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled $0.2

million in the second quarter of 2005 and $0.5 million in the same period in 2004. Our total interest cost in the second quarter of 2005 was $8.0 million, of which $1.7 million was capitalized. Our total interest cost in the second quarter of 2004 was $8.8 million, of which $1.6 million was capitalized. We capitalize a portion of interest related to unproved properties. The decrease of interest expense in the second quarter of 2005 was primarily attributable to the replacement of our 10-1/4% senior subordinated notes with our 7-5/8% senior notes.

In the second quarter of 2004, we incurred $2.7 million of debt retirement costs related to the repurchase of a portion of our 10-1/4% senior subordinated notes due 2009 pursuant to a tender offer. 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 $0.1 million of other costs.

Our overall effective tax rate was 33.3% in the second quarter of 2005 and 35.5% in the same 2004 period. The effective income tax rate for both the second quarter of 2005 and 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. Additionally, the second quarter of 2005 rate is lower due to a favorable correction in the New Zealand tax basis of oil and gas properties.

Net Income. For the second quarter of 2005, our net income of $27.9 million was 116% higher, and Basic EPS of $0.98 was 111% higher, than our second quarter of 2004 net income of $12.9 million and Basic EPS of $0.46. Our Diluted EPS in the second quarter of 2005 of $0.96 was 111% higher than our second quarter 2004 Diluted EPS of $0.46. These higher amounts are due to our increased oil and gas revenues, which in turn were higher due to continued strong commodity prices and our increased production during the second quarter of 2005.

Results of Operations - Six Months Ended June 30, 2005 and 2004

Revenues. Our revenues in the first six months of 2005 increased by 47% compared to revenues in the same period in 2004, due primarily to an increase in commodity prices and production from our Lake Washington area and, to a lesser extent, Rimu/Kauri area. Revenues from our oil and gas sales comprised substantially all of net revenues for the first half of 2005 and 2004. In the first six months of 2005, oil production made up 52% of total production, natural gas made up 39%, and NGL represented 9%. In the first six months of 2004, oil production made up 48% of total production, natural gas made up 41%, and NGL represented 11%. The increase in the percentage of our total production from oil is because production from Lake Washington is almost entirely crude oil, and production from this area has increased significantly as a result of our continued development in the field.

Our first six months of 2005 weighted average prices increased 32% to $6.38 per Mcfe from $4.83 in the first six months of 2004, with per barrel oil prices appreciating 37% to $49.00 from $35.70 during the first half of 2004, per Mcfe natural gas prices increasing 14% to $4.46 from $3.91, and per barrel NGL prices rose 21% to $24.94 from $20.60.

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

The following table sets forth our revenue from oil and gas sales and the volumes underlying those sales from each of our core areas for the six months ended June 30, 2005 and 2004, illustrating the changes between the two periods:

	Six Months Ended June 30,			
Area	Oil and Gas Sales (In Millions)		Net Oil and Gas Sales V	
	2005	2004	2005	
AWP Olmos	$ 24.3	$ 24.3	3.8	
Brookeland	8.1	9.3	1.4	
Lake Washington	113.5	61.6	14.6	
Masters Creek	9.1	10.6	1.5	
Other	11.7	8.6	1.6	
Total Domestic	$ 166.7	$ 114.4	22.9	
Rimu/Kauri	21.7	9.5	4.3	
TAWN	12.0	13.8	4.2	
Total New Zealand	$ 33.7	$ 23.4	8.5	
Total	$ 200.4	$ 137.8	31.4	

The following table breaks down our sales volumes by commodity and provides average sales prices for each commodity for the six months ending June 30, 2005 and 2004:

	Sales Volume				Average S	
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (Bcfe)	Oil (Bbl)	NG (Bb
2005						
Six Months Ended June 30:						
Domestic	2,523	262	6.2	22.9	$48.79	$29
New Zealand	224	170	6.2	8.5	$51.35	$18
Total	2,747	432	12.4	31.4	$49.00	$24
2004						

Six Months Ended June 30:						
Domestic	2,039	390	6.1	20.6	$35.59	$22
New Zealand	228	157	5.6	7.9	$36.74	$16
Total	2,267	547	11.7	28.5	$35.70	$20

In the first six months of 2005, our $62.7 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $45.2 million favorable impact on sales, of which $36.5 million was attributable to the 37% increase in average oil prices received, $6.8 million was attributable to the 14% increase in average gas prices received, and $1.9 million was attributable to the 21% increase in average NGL prices received; and

- Volume variances that had a $17.5 million favorable impact on sales, with $17.1 million of increases coming from the 480,000 Bbl

increase in oil sales volumes, $2.7 million of increases due to the 0.7 Bcf increase in gas sales volumes, partially offset by a $2.4 million decrease attributable to the 115,000 Bbl decrease in NGL sales volumes.

Costs and Expenses. Our expenses in the first six months of 2005 increased $22.1 million, or 23%, compared to expenses in the same period of 2004. The increase was due to a $15.2 million increase in DD&A, a $6.7 million increase in severance and other taxes, and a $2.6 million increase in lease operating costs, all of which are primarily due to increased production volumes and high oil and gas prices in the first six months of 2005. These cost increases in the first six months of 2005 were partially offset by debt retirement costs that were incurred in the first six months of 2004, which totaled $2.7 million.

Our first six months of 2005 general and administrative expenses, net, increased $1.7 million, or 20%, from the level of such expenses in the same 2004 period. This increase was primarily due to an increase in workforce, resulting in increased salaries and benefits, and due to the continued costs of compliance initiatives related to the Sarbanes-Oxley Act. Our net general and administrative expenses per Mcfe produced increased to $0.31 per Mcfe in the first half of 2005 from $0.29 per Mcfe in the same 2004 period. For the first six months of 2005 and 2004, our capitalized general and administrative costs totaled $8.8 million and $6.2 million, respectively. The portion of supervision fees recorded as a reduction to general and administrative expenses was $3.8 million for the first six months of 2005 and $2.5 million for the 2004 period.

DD&A increased $15.2 million, or 40%, in the first six months of 2005 from the level of those expenses in the same period of 2004. Domestically, DD&A increased $10.8 million in the first half of 2005 due to increases in the depletable oil and gas property base including future development costs and higher production in the 2005 period. In New Zealand, DD&A increased by $4.4 million in the first half of 2005 due to increases in the depletable oil and gas property base, higher production in the 2005 period and lower reserve volumes than in the same 2004 period. Our DD&A rate per Mcfe of production was $1.69 and $1.32 in the first six months of 2005 and 2004, respectively.

We recorded $0.4 million of accretions to our asset retirement obligation in the first six months of 2005 and $0.3 million in the same period of 2004.

Our lease operating costs per Mcfe produced were $0.72 in the first six months of 2005 and $0.70 in the 2004 period. Our lease operating costs in the first half of 2005 increased $2.6 million, or 13%, over the level of such expenses in the same 2004 period. Approximately $1.9 million of the increase was related to our domestic operations, which increased primarily due to higher production from our Lake Washington area. Our lease operating costs in New Zealand increased in the first half of 2005 by $0.7 million due to higher plant operating expenses, an increase in the New Zealand dollar exchange rate and higher production in the Rimu/Kauri area partially offset by the decline in the TAWN area.

In the first six months of 2005, severance and other taxes increased $6.7 million, or 51%, over levels in the first six months of 2004. The increase was due primarily to higher commodity prices and increased Lake Washington and Rimu/Kauri production in the period. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than in the other states where we have production. As our percentage of oil production in Louisiana increases, the overall percentage of severance costs to sales also increases. Severance and other taxes, as a percentage of oil and gas sales, were approximately 9.9% and 9.6% in the first half of 2005 and 2004, respectively.

Interest expense on our 7-5/8% senior notes due 2011 issued in June 2004, including amortization of debt issuance costs, totaled $5.9 million in the first six months of 2005 and $0.2 million in the same 2004 period, which was the period these notes were issued and the 10-1/4% senior subordinated notes were retired. Interest expense on our 9-3/8% senior subordinated notes due 2012 issued in April 2002, including amortization of debt issuance costs, totaled $9.6 million in both the first six months of 2005 and 2004. Interest expense on our 10-1/4% senior subordinated notes issued in August 1999 and retired in 2004, including amortization of debt issuance costs, totaled $6.6 million in the first six months of 2004. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled $0.6 million in the first six months of 2005 and $0.9 million in the same period in 2004. Our total interest cost in the first six months of 2005 was $16.1 million, of which $3.5 million was capitalized. Our total interest cost in the first six months of 2004 was $17.3 million, of which $3.2 million was capitalized. We capitalize a portion of interest related to unproved properties. The decrease of interest expense in the first six months of 2005 was primarily attributable to the replacement of our 10-1/4% senior subordinated notes with our 7-5/8% senior notes.

In the first six months of 2004, we incurred $2.7 million of debt retirement costs related to the repurchase of a portion of our 10-1/4% senior subordinated notes pursuant to a tender offer. 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 $0.1 million of other costs.

Our overall effective tax rate was 34.3% in the first six months of 2005 and 31.4% in the same 2004 period. The effective income tax rate for both the first six months of 2005 and 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. Both the first six months of 2005 and 2004 also included reductions in tax expense primarily attributable to an adjustment of the tax basis of the TAWN properties, which were acquired in 2002.

Net Income. For the first six months of 2005, our net income of $53.6 million was 95% higher, and Basic EPS of $1.90 was 91% higher, than our first half of 2004 net income of $27.5 million and Basic EPS of $0.99. Our Diluted EPS in the first six months of 2005 of $1.86 was 90% higher than our first half 2004 Diluted EPS of $0.98. These higher amounts are due to our increased oil and gas revenues, which in turn were higher due to continued strong commodity prices and our increased production during the first six months of 2005.

Contractual Commitments and Obligations

We had no material changes in our contractual commitments and obligations from December 31, 2004 amounts referenced in our Annual Report on Form 10-K for the period ending December 31, 2004.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and are expected to continue to be volatile in the future. The price of oil has increased over the last two years and is currently at record highs when compared to longer-term historical prices. Factors such as geopolitical activities, worldwide supply disruptions, worldwide economic conditions, weather conditions, actions taken by OPEC, and fluctuating currency exchange rates can cause wide fluctuations in the price of oil. Domestic natural gas prices continue to remain 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 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. We do not believe the recently enacted American Jobs Creation Act of 2004 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 six months of 2005, we relied upon our net cash provided by operating activities of $129.3 million to fund capital expenditures of $101.8 million and to pay down our bank borrowings by $7.5 million. During the first six months of 2004, we largely relied upon our net cash provided by operating activities of $77.1 million and proceeds from the offering of our 7-5/8% senior notes due 2011 of $150.0 million to fund capital expenditures of $85.9 million,

repurchase $32.1 million of our 10-1/4% senior subordinated notes due 2009, and repay all outstanding indebtedness under our bank credit facility.

Net Cash Provided by Operating Activities. For the first six months of 2005, our net cash provided by operating activities was $129.3 million, representing a 68% increase as compared to $77.1 million generated during the same 2004 period. The $52.2 million increase in the first six months of 2005 was primarily due to an increase of $62.7 million in oil and gas sales, attributable to higher commodity prices and production, offset in part by higher lease operating costs due to higher production and severance taxes.

Accounts Receivable. Included in the "Accounts receivable" balance, which totaled $46.9 million and $39.0 million at June 30, 2005 and December 31, 2004, 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. As a result of the dispute, we did not record a receivable with regard to any 2003 disputed volumes and our contract governing these sales expired in 2003. Based on settlement discussions, we settled our claim with this counter-party in July 2005 by receiving a cash payment for less than our gross receivable. Accordingly, in the second quarter of 2005, we increased our reserve for this claim by approximately $0.6 million, which is recorded in "Price-risk management and other, net" on the accompanying statements of income.

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 June 30, 2005 and December 31, 2004, we had an allowance for doubtful accounts of $1.0 million and $0.5 million, respectively. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying balance sheets.

Bank Credit Facility. We had no borrowings under our bank credit facility at June 30, 2005, and $7.5 million in outstanding borrowings at December 31, 2004. Our bank credit facility at June 30, 2005 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 May 1, 2005. We maintained the commitment amount at $150.0 million, which amount was set at our request effective May 9, 2003. 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 adjusted working capital ratios and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of this agreement.

Our access to funds from our credit facility is not restricted under any "material adverse condition" clause, a clause that is common for credit agreements to include. A "material adverse condition" clause can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have an adverse or material effect on our operations, financial condition, prospects or properties, and would impair our ability to make timely debt repayments. Our credit facility includes covenants that require us to report events or conditions having a material adverse effect on our financial condition. The obligation of the banks to fund the credit facility is not conditioned on the absence of a material adverse effect.

Debt Maturities. Our credit facility extends until October 1, 2008. Our $150.0 million of 7-5/8% senior notes mature July 15, 2011, and our $200.0 million of 9-3/8% senior subordinated notes mature May 1, 2012.

Working Capital. Our working capital improved from a deficit of $14.2 million at December 31, 2004, to a surplus of $13.7 million at June 30, 2005. The improvement primarily resulted from an increase in our cash balances due to increased cash flows from operating activities and an increases in oil and gas sales receivables due to increased production and commodity pricing from year-end 2004 levels.

Capital Expenditures. In the first six months of 2005, we relied upon our net cash provided by operating activities of $129.3 million to fund total capital expenditures of $101.8 million in the first six months of 2005, which included:

Domestic expenditures of $67.6 million as follows:

- $54.7 million for drilling and developmental activity costs, predominantly in our Lake Washington and AWP areas;

- $11.6 million of domestic prospect costs, principally prospect leasehold, activity, and geological costs of unproved prospects;

- $1.2 million primarily for a field office building, computer equipment, software, furniture, and fixtures;

- less than $0.1 million on gas processing plants in the Brookeland and Masters Creek areas.

New Zealand expenditures of $34.2 million as follows:

- $ 30.0 million for drilling and developmental activity costs;

- $3.7 million on prospect costs and geological costs of unproved properties;

- $0.4 million on gas processing plants;

- and $0.1 million for computer equipment, software, furniture, and fixtures.

We successfully completed 27 of 39 wells in the first six months of 2005, for a success rate of 69%. Domestically, we completed 23 of 29 development wells for a success rate of 79% and completed three of four exploration wells during the first six months of 2005. During the same period, a total of 24 wells were drilled in the Lake Washington area, of which 17 were completed; eight wells were drilled in the AWP Olmos area and all were completed, and one non-operated well was drilled in the Brookeland area and was completed. In New Zealand during the first six months of 2005, we drilled five development wells, one was successful, and one exploratory well which was unsuccessful.

For the last six months of 2005, we expect to make capital expenditures of approximately $120 to $140 million. Our current estimated total capital expenditures for 2005 continue to be approximately $220 to $240 million, excluding acquisition costs and net of approximately $5 million to $15 million in non-core property dispositions. These estimated 2005 amounts include an increase of approximately $20 million due to higher drilling and services costs over prior year levels. Capital expenditures for 2004 were $198 million.

If producing property acquisitions become attractive during the remaining six months of 2005, we will explore the use of debt and/or equity offerings, along with using our cash flows in excess of capital expenditures, to fund any such acquisition.

During the last six months of 2005, we anticipate drilling or participating in the drilling of up to an additional 13 to 17 wells in the Lake Washington area, an additional 4 to 7 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 4 to 6 wells in New Zealand.

Our 2005 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 2005 total production to increase over 2004 levels, primarily from the Lake Washington, Bay de Chene, Cote Blanche Island 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. For 2005, based upon our progress to date and planned activities for

the remainder of the year, we estimate our total production to increase 10% to 14%, or approximately 64.0 Bcfe to 66.5 Bcfe, and estimate that proved reserves will increase 5% to 10%, both over 2004 levels.

New Accounting Pronouncements

In September and November 2004, and March 2005, the EITF discussed a proposed framework for addressing when a limited partnership should be consolidated by its general partner, EITF Issue 04-5. The proposed framework presumes that a sole general partner in a limited partnership controls the limited partnership, and therefore should consolidate the limited partnership. The presumption of control can be overcome if the limited partners have (a) the substantive ability to remove the sole general partner or otherwise dissolve the limited partnership or (b) substantive participating rights. The EITF reached a tentative conclusion on the circumstances in which either kick-out rights or participating rights would be considered substantive and preclude consolidation by the general partner and what limited partner's rights would be considered participating rights that would preclude consolidation by the general partner. The EITF tentatively concluded that for kick-out rights to be considered substantive, the conditions specified in paragraph B20 of FIN 46R should be met. With regard to the definition of participating rights that would preclude consolidation by the general partner, the EITF concluded that the definition of those rights should be consistent with those in EITF Issue 96-16. The EITF also reached a tentative conclusion on the transition for Issue 04-05. The FASB ratified the EITF consensus at the June 2005 EITF meeting. We do not believe this EITF will have a material impact on our consolidated financial statements because we believe our limited partners have substantive kick-out rights under paragraph B20 of FIN 46R.

In December 2004, the FASB issued SFAS No. 123R, Share-Based Payment. SFAS No. 123R is a revision of SFAS No. 123, Accounting for Stock-Based Compensation, and supercedes APB Opinion No. 25, Accounting for Stock Issued to Employees, and amends SFAS No. 95, Statement of Cash Flows. SFAS No. 123R requires all employee share-based payments, including grants of employee stock options, to be recognized in the financial statements based on their fair values. SFAS No. 123 discontinues the ability to account for these equity instruments under the intrinsic value method as described in APB Opinion No. 25. SFAS No. 123R requires the use of an option pricing model for estimating fair value, which is amortized to expense over the service periods. The requirements of SFAS No. 123R are effective for fiscal periods beginning after June 15, 2005. SFAS No. 123R permits public companies to adopt its requirements using one of two methods:

- o A "modified prospective" method in which compensation cost is recognized beginning with the effective date based on the requirements of SFAS No. 123R for all share-based payments granted after the effective date and based on the requirements of SFAS No. 123 for all awards granted to employees prior to the adoption date of SFAS No. 123R that remain unvested on the adoption date.

- o A "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS No. 123 for purposes of pro forma disclosures.

In April 2005, the SEC issued a release announcing that it would provide for a phased-in implementation process for SFAS No. 123R. As a result, our required date to adopt SFAS No. 123R is now January 1, 2006. Also in April 2005, the SEC issued Staff Accounting Bulleting No. 107, Share-Based Payment, which provides guidance on the implementation of SFAS No. 123R. SAB No. 107 provides guidance on valuing options, estimating volatility and expected terms of the option awards, and discusses the SEC's views on share-based payment transactions with non-employees, the capitalization of compensation cost and accounting for income tax effects of share-based payment arrangements upon adoption of SFAS No. 123R.

We have elected to adopt the provisions of SFAS No. 123R on January 1, 2006 using the modified prospective method. As permitted by Statement 123, the Company currently accounts for share-based payments to employees using APB Opinion No. 25's intrinsic value method and, as

such, generally recognizes no compensation cost for employee stock options. Accordingly, the adoption of Statement No. 123R's fair value method is expected to have a significant impact on our results of operations. However, it will have no impact on our overall financial position. We currently use the Black-Scholes formula to estimate the value of stock options granted to employees and expect to continue to use this acceptable option valuation model upon the required adoption of SFAS No. 123R. The significance of the impact of adoption will depend on levels of outstanding unvested share-based payments on the date of adoption and share-based payments granted in the future. However, had we adopted Statement No. 123R in prior periods, the impact of that standard would have approximated the impact of Statement No. 123 as described in the disclosure of pro forma net income and earnings per share under "Stock Based Compensation" above.

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and

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

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

In July 2005, the FASB issued an exposure draft "Accounting for Uncertain Tax Positions, a proposed interpretation of FASB Statement No. 109." The proposed interpretation would apply to all open tax positions under FASB No. 109. The conclusions in this interpretation include: initial recognition of tax benefits, recognition and de-recognition of tax positions, measurement of tax benefits and classifications of tax liabilities. The comment period on this exposure draft ends in September 2005, and we are currently assessing the impact, if any, that this interpretation would have on our financial position and results of operations. The proposal enactment date would require application effective December 31, 2005.

New Developments

Petroleum Mining Permit 38155. In April 2005, Swift Energy New Zealand ("SENZ") was awarded petroleum mining permit ("PMP") 38155 by the New Zealand Government, for the development of our Kauri Sand and Manutahi Sand discoveries. The PMP 38155 mining permit covers 8,708 acres and allows us to fully develop our Kauri area for a primary term of 30 years.

Petroleum Exploration Permit 38495. In April 2005, Swift Energy New Zealand ("SENZ") was awarded petroleum exploration permit ("PEP") 38495 by the New Zealand Government. Following the award of PEP 38495, SENZ initiated a farm-in agreement with Mighty River Power ("MRP"), whereby SENZ agreed to transfer a 50% interest in the permit to MRP in return for MRP funding various seismic operations during 2005 and 2006. PEP 38495 is located offshore in the southern portion of the basin to the south and west of our PEP 38719 and encompasses approximately 600 square miles.

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 the uncertainty of finding, replacing, developing or acquiring reserves; the uncertainty of drilling results and reserve estimates; damage to operations or decreased production due to hurricanes or tropical storms; operating hazards; availability of equipment, services or supplies; changes in geologic or engineering information; geopolitical events; volatility in oil and gas prices; fluctuations of demand for our oil and natural gas; changes in market conditions; increased competition; and government regulations; as well as the risks and uncertainties 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, expected increases in development costs and other factors, interim results are not necessarily indicative of those for a full year.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

Commodity Risk

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

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

- Price Floors - At June 30, 2005, we had in place price floors in effect through the December 2005 contract month for natural gas, which cover 30% to 35% of our estimated domestic natural gas production for July 2005 to December 2005. The natural gas price floors cover notional volumes of 2,300,000 MMBtu, and expire at various dates from July 2005 to December 2005, with a weighted average floor price of $5.71 per MMBtu.

- New Zealand Gas Contracts - Almost 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 financial position or results of operations.

Foreign Currency Risk

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

Interest Rate Risk

Our 7-5/8% senior notes due 2011 and 9-3/8% 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 these notes may exceed those payments based on the current market rate. At June 30, 2005, we had no 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 60 basis points and would not have a material adverse effect on our 2005 cash flows based on this same level or a modest level of borrowing.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in our filings under the Securities and Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. Our chief executive officer and chief financial officer have evaluated our disclosure controls and procedures as of the end of the period covered by this report and have concluded that such disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this report is accumulated and communicated to them and our management to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the second quarter of 2005 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

SWIFT ENERGY COMPANY

PART II. - OTHER INFORMATION

Item 1. Legal Proceedings

No material legal proceedings are pending other than ordinary, routine litigation incidental to the Company's business.

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

Item 3. Defaults Upon Senior Securities - None

Item 4. Submission of Matters to a Vote of Security Holders -

Our annual meeting of shareholders was held on May 10, 2005. At the record date, 28,222,966 shares of common stock were outstanding and entitled to one vote per share upon all matters submitted at the meeting. At the annual meeting, three nominees were elected to serve as Directors of Swift for three year terms to expire at the 2008 annual meeting of shareholders:

NOMINEES FOR DIRECTORS	FOR	WITHHELD
Deanna L. Cannon	23,693,494	2,562,363
Douglas J. Lanier	23,691,491	2,564,366
Bruce H. Vincent	20,663,780	5,592,077

The terms of directors Raymond E. Galvin, Clyde W. Smith, Jr., Terry E. Swift expire at the 2006 annual meeting and the terms of directors A. Earl Swift, Greg Matiuk and Henry C. Montgomery expire at the 2007 annual meeting.

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: August 5, 2005 By: (original signed by)

------------------ ---------------------------------
Alton D. Heckaman, Jr.
Executive Vice President
Chief Financial Officer

Date: August 5, 2005 By: (original signed by)

------------------ ---------------------------------
David W. Wesson
Controller and Principal
Accounting Officer

Exhibit 31.1

CERTIFICATION

I, Terry E. Swift, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the period ended June 30, 2005, 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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15(d)-15(f)) 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting, to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) 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

d) 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: August 5, 2005

/s/ Terry E. Swift

Terry E. Swift
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

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

1. I have reviewed this Quarterly Report on Form 10-Q for the period ended June 30, 2005, 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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15(d)-15(f)) 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting, to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) 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

d) 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: August 5, 2005

/s/ Alton D. Heckaman, Jr.

Alton D. Heckaman, Jr.
Executive Vice President - Chief Financial Officer

Exhibit 32

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 June 30, 2005 (the "Report") of Swift Energy Company ("Swift") as filed with the Securities and Exchange Commission on August 5, 2005, 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: August 5, 2005

/s/ Alton D. Heckaman, Jr.

Alton D. Heckaman, Jr.
Executive Vice President - Chief Financial Officer

Dated: August 5, 2005

/s/ Terry E. Swift

Terry E. Swift
Chief Executive Officer