

UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549

FORM 10-Q

(X) QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE  
SECURITIES EXCHANGE ACT OF 1934

**For the Quarterly Period Ended September 30, 2006**

Commission File Number 1-8754

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

TEXAS  
(State of Incorporation)

20-3940661  
(I.R.S. Employer Identification No.)

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

77060  
(Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.  
Yes  No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer  Accelerated filer  Non-accelerated filer

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

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

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

29,527,985 Shares  
(Outstanding at October 31, 2006)

**SWIFT ENERGY COMPANY**  
**FORM 10-Q**  
**FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2006**

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## Condensed Consolidated Balance Sheets

### Swift Energy Company and Subsidiaries

	September 30, 2006	December 31, 2005
<b>ASSETS</b>		
Current Assets:		
Cash and cash equivalents	\$ 95,117,902	\$ 53,004,562
Accounts receivable-		
Oil and gas sales	59,980,011	45,518,260
Joint interest owners	1,167,963	1,082,187
Other Receivables	17,701,312	3,795,080
Other current assets	38,394,344	11,655,046
Total Current Assets	212,361,532	115,055,135
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	1,979,294,070	1,731,866,298
Unproved properties	84,541,410	87,553,220
	2,063,835,480	1,819,419,518
Furniture, fixtures, and other equipment	26,701,704	15,313,277
	2,090,537,184	1,834,732,795
Less – Accumulated depreciation, depletion, and amortization	(875,819,720)	(755,699,056)
	1,214,717,464	1,079,033,739
Other Assets:		
Debt issuance costs	7,130,221	8,026,780
Restricted assets	2,293,895	2,296,968
	9,424,116	10,323,748
	\$ 1,436,503,112	\$ 1,204,412,622
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>		
Current Liabilities:		
Accounts payable and accrued liabilities	\$ 55,293,512	\$ 51,973,004
Accrued capital costs	42,974,178	30,073,728
Accrued interest	10,336,338	8,508,196
Undistributed oil and gas revenues	8,948,655	7,866,086
Total Current Liabilities	117,552,683	98,421,014
Long-Term Debt	350,000,000	350,000,000
Deferred Income Taxes	196,797,908	129,306,891
Asset Retirement Obligation	20,089,268	19,095,368
Lease Incentive Obligation	1,787,893	271,182
Commitments and Contingencies		
Stockholders' Equity:		
Preferred stock, \$.01 par value, 5,000,000 shares authorized, none outstanding	---	---
Common stock, \$.01 par value, 85,000,000 shares authorized, 29,727,913 and 29,458,974 shares issued, and 29,300,827 and 29,009,530 shares outstanding, respectively	297,279	294,590
Additional paid-in capital	374,559,260	365,085,695
Treasury stock held, at cost, 427,086 and 449,444 shares, respectively	(6,124,944)	(6,445,586)
Unearned compensation	---	(5,849,820)
Retained earnings	380,597,278	254,302,757
Accumulated other comprehensive income (loss), net of income tax	946,487	(69,469)
	750,275,360	607,318,167
	\$ 1,436,503,112	\$ 1,204,412,622

See accompanying notes to condensed consolidated financial statements.

## Condensed Consolidated Statements of Income

### Swift Energy Company and Subsidiaries

	Three Months Ended		Nine Months Ended	
	09/30/06	09/30/05	09/30/06	09/30/05
<b>Revenues:</b>				
Oil and gas sales	\$ 173,368,549	\$ 101,007,524	\$ 453,315,519	\$ 301,451,257
Price-risk management and other, net	90,303	(154,019)	3,489,510	(677,143)
	<u>173,458,852</u>	<u>100,853,505</u>	<u>456,805,029</u>	<u>300,774,114</u>
<b>Costs and Expenses:</b>				
General and administrative, net	8,018,260	5,803,946	23,323,223	15,674,141
Depreciation, depletion and amortization	45,867,715	23,870,287	120,151,446	76,853,296
Accretion of asset retirement obligation	171,545	191,529	665,812	565,531
Lease operating costs	12,926,110	12,221,153	45,843,648	34,835,158
Severance and other taxes	18,489,838	9,670,565	49,210,714	29,582,400
Interest expense, net	5,776,220	6,194,370	17,436,326	18,825,273
	<u>91,249,688</u>	<u>57,951,850</u>	<u>256,631,169</u>	<u>176,335,799</u>
Income Before Income Taxes	82,209,164	42,901,655	200,173,860	124,438,315
Provision for Income Taxes	31,397,597	15,394,756	73,879,339	43,360,606
Net Income	<u>\$ 50,811,567</u>	<u>\$ 27,506,899</u>	<u>\$ 126,294,521</u>	<u>\$ 81,077,709</u>
<b>Per Share Amounts</b>				
Basic: Net Income	<u>\$ 1.74</u>	<u>\$ .96</u>	<u>\$ 4.33</u>	<u>\$ 2.86</u>
Diluted: Net Income	<u>\$ 1.68</u>	<u>\$ .92</u>	<u>\$ 4.20</u>	<u>\$ 2.77</u>
Weighted Average Shares Outstanding	<u>29,251,945</u>	<u>28,632,895</u>	<u>29,161,278</u>	<u>28,390,120</u>

See accompanying notes to condensed consolidated financial statements.

## Condensed Consolidated Statements of Stockholders' Equity

### Swift Energy Company and Subsidiaries

	<u>Common Stock(1)</u>	<u>Additional Paid-In Capital</u>	<u>Treasury Stock</u>	<u>Unearned Compensation</u>	<u>Retained Earnings</u>	<u>Other Comprehensive Income (Loss)</u>	<u>Total</u>
Balance, December 31, 2004	\$ 285,706	\$ 343,536,298	\$ (6,896,245)	\$ (1,728,585)	\$ 138,524,301	\$ 450,665	\$ 474,172,140
Stock issued for benefit plans (31,424 shares)	---	435,134	450,659	---	---	---	885,793
Stock options exercised (840,847 shares)	8,409	9,804,555	---	---	---	---	9,812,964
Tax benefits from exercise of stock options	---	4,366,236	---	---	---	---	4,366,236
Employee stock purchase plan (32,495 shares)	325	642,354	---	---	---	---	642,679
Issuance of restricted stock (15,000 shares)	150	---	---	---	---	---	150
Grants of restricted stock (158,500 shares)	---	6,668,608	---	(6,072,008)	---	---	596,600
Forfeitures of restricted stock	---	(367,490)	---	367,490	---	---	---
Amortization of restricted stock compensation	---	---	---	1,583,283	---	---	1,583,283
Comprehensive Income:							
Net income	---	---	---	---	115,778,456	---	115,778,456
Other Comprehensive Income	---	---	---	---	---	(520,134)	(520,134)
Total Comprehensive Income	---	---	---	---	---	---	115,258,322
<b>Balance, December 31, 2005</b>	<b><u>\$ 294,590</u></b>	<b><u>\$ 365,085,695</u></b>	<b><u>\$ (6,445,586)</u></b>	<b><u>\$ (5,849,820)</u></b>	<b><u>\$ 254,302,757</u></b>	<b><u>\$ (69,469)</u></b>	<b><u>\$ 607,318,167</u></b>
Stock issued for benefit plans (22,358 shares)	---	714,049	320,642	---	---	---	1,034,691
Stock options exercised (210,738 shares)	2,107	3,615,470	---	---	---	---	3,617,577
Adoption of SFAS No. 123R	---	(5,875,280)	---	5,849,820	---	---	(25,460)
Excess tax benefits from stock-based awards	---	2,772,329	---	---	---	---	2,772,329
Employee stock purchase plan (22,425 shares)	224	671,106	---	---	---	---	671,330
Issuance of restricted stock (35,776 shares)	358	(358)	---	---	---	---	---
Amortization of stock compensation	---	7,576,249	---	---	---	---	7,576,249
Comprehensive Income:							
Net income	---	---	---	---	126,294,521	---	126,294,521
Other Comprehensive Income	---	---	---	---	---	1,015,956	1,015,956
Total Comprehensive Income	---	---	---	---	---	---	127,310,477
<b>Balance, September 30, 2006</b>	<b><u>\$ 297,279</u></b>	<b><u>\$ 374,559,260</u></b>	<b><u>\$ (6,124,944)</u></b>	<b><u>\$ ---</u></b>	<b><u>\$ 380,597,278</u></b>	<b><u>\$ 946,487</u></b>	<b><u>\$ 750,275,360</u></b>

(1) \$.01 Par Value

See accompanying notes to condensed consolidated financial statements.

## Condensed Consolidated Statements of Cash Flows

### Swift Energy Company and Subsidiaries

	Nine Months Ended September 30,	
	2006	2005
<b>Cash Flows from Operating Activities:</b>		
Net income	\$ 126,294,521	\$ 81,077,709
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion, and amortization	120,151,446	76,853,296
Accretion of asset retirement obligation	665,812	565,531
Deferred income taxes	67,169,122	42,610,606
Stock-based compensation expense	5,057,142	1,005,904
Other	(3,678,105)	1,230,677
Change in assets and liabilities-		
(Increase) decrease in accounts receivable	(14,547,527)	15,162,260
Increase in accounts payable and accrued liabilities	7,404,437	739,152
Increase in income taxes payable	337,716	87,551
Increase in accrued interest	1,828,142	1,127,146
Net Cash Provided by Operating Activities	<u>310,682,706</u>	<u>220,459,832</u>
<b>Cash Flows from Investing Activities:</b>		
Additions to property and equipment	(291,308,227)	(158,125,266)
Proceeds from the sale of property and equipment	20,336,133	2,387,293
Net cash distributed as operator of oil and gas properties	(4,193,748)	(2,183,944)
Net cash received (distributed) as operator of partnerships and joint ventures	854,672	(467,534)
Other	(30,782)	64,480
Net Cash Used in Investing Activities	<u>(274,341,952)</u>	<u>(158,324,971)</u>
<b>Cash Flows from Financing Activities:</b>		
Payments of bank borrowings	---	(7,500,000)
Net proceeds from issuances of common stock	4,288,907	6,329,431
Excess tax benefits from stock-based awards	1,483,679	---
Net Cash Provided by (Used in) Financing Activities	<u>5,772,586</u>	<u>(1,170,569)</u>
Net Increase in Cash and Cash Equivalents	\$ 42,113,340	\$ 60,964,292
Cash and Cash Equivalents at Beginning of Period	<u>53,004,562</u>	<u>4,920,118</u>
Cash and Cash Equivalents at End of Period	<u>\$ 95,117,902</u>	<u>\$ 65,884,410</u>
<i>Supplemental Disclosures of Cash Flows Information:</i>		
Cash paid during period for interest, net of amounts capitalized	\$ 14,721,356	\$ 16,887,396
Cash paid during period for income taxes	\$ 6,372,500	\$ 750,000

See accompanying notes to condensed consolidated financial statements.

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS SWIFT ENERGY COMPANY AND SUBSIDIARIES

### (1) General Information

The condensed consolidated financial statements included herein have been prepared by Swift Energy Company and reflect necessary adjustments, all of which were of a recurring nature, and are in the opinion of our management necessary for a fair presentation. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission. We believe that the disclosures presented are adequate to allow the information presented not to be misleading. The condensed consolidated financial statements should be read in conjunction with the audited financial statements and the notes thereto included in the latest Annual Report on Form 10-K as filed with the Securities and Exchange Commission.

### (2) Summary of Significant Accounting Policies

#### *Holding Company Structure*

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

#### *Property and Equipment*

We follow the "full-cost" method of accounting for oil and gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the nine months ended September 30, 2006 and 2005, such internal costs capitalized totaled \$20.7 million and \$13.4 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the nine months ended September 30, 2006 and 2005, capitalized interest on unproved properties totaled \$6.6 million and \$5.3 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

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued

### SWIFT ENERGY COMPANY AND SUBSIDIARIES

are amortized to expense as our capitalized oil and gas property costs are amortized.

We compute the provision for depreciation, depletion, and amortization of oil and gas properties by the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties—including future development costs, natural gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties—by an overall rate determined by dividing the physical units of oil and gas produced during the period by the total estimated units of proved oil and gas reserves at the beginning of the period. This calculation is done on a country-by-country basis, and the period over which we will amortize these properties is dependent on our production from these properties in future years. Furniture, fixtures, and other equipment, held at cost, are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between two and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

Geological and geophysical (G&G) costs incurred on developed properties are recorded in “Proved properties” and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in “Unproved properties” and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is assessed quarterly, on a country-by-country basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, foreign currency exchange rates, the political stability in the countries in which we have an investment, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized. To the extent costs accumulate in countries where there are no proved reserves, any costs determined by management to be impaired are charged to expense.

#### *Full-Cost Ceiling Test.*

At the end of each quarterly reporting period, the unamortized cost of oil and gas properties, including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability is limited to the sum of the estimated future net revenues from proved properties, excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects (“Ceiling Test”). Our hedges at September 30, 2006 consisted of crude oil price floors with strike prices higher than the period end price but did not materially affect prices used in this calculation. This calculation is done on a country-by-country basis.

The calculation of the Ceiling Test and provision for depreciation, depletion, and amortization (“DD&A”) is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered.

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

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

*Principles of Consolidation*

The accompanying consolidated financial statements include the accounts of Swift Energy Company and its wholly owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and natural gas properties, with a focus on inland waters and onshore oil and natural gas reserves in Louisiana and Texas, as well as onshore oil and natural gas reserves in New Zealand. Our undivided interests in natural gas processing plants, and investments in oil and gas limited partnerships where we are the general partner are accounted for using the proportionate consolidation method, whereby our proportionate share of each entity's assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying consolidated financial statements.

*Revenue Recognition*

Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. Processing costs for natural gas and natural gas liquids (NGLs) that are paid in-kind are deducted from revenues. The Company uses the entitlement method of accounting in which the Company recognizes its ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying balance sheet. Natural gas balancing receivables are reported in "Other current assets" on the accompanying balance sheet when our ownership share of production exceeds sales. As of September 30, 2006, we did not have any material natural gas imbalances.

*Accounts Receivable*

We assess the collectibility of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At both September 30, 2006 and December 31, 2005, we had an allowance for doubtful accounts of less than \$0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying balance sheets. Receivables related to insurance reimbursement are computed in accordance with applicable accounting guidance; and we monitor our costs incurred and their collectibility under our insurance policies and believe all amounts recorded are recoverable.

*Inventories*

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

	Balance at September 30, 2006 (000's)	Balance at December 31, 2005 (000's)
Materials, Supplies and Tubulars	\$ 11,146	\$ 8,494
Crude Oil	662	916
Total	<u>\$ 11,808</u>	<u>\$ 9,410</u>

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

### *Use of Estimates*

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

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage,
- estimates of stock compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,
- the estimated future cost and timing of asset retirement obligations, and
- estimates made in our income tax calculations.

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

### *Income Taxes*

Under SFAS No. 109, “Accounting for Income Taxes,” deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws. The effective tax rate for the nine months ended September 30, 2006 and 2005 was higher than the U.S. Federal statutory tax rate primarily due to state income taxes, partially offset by reductions from the New Zealand statutory rate attributable to the currency effect on the New Zealand deferred tax calculation. As of September 30, 2006, we believe we have utilized all of our U.S. federal operating loss carryforwards during the 2006 tax year.

### *Accounts Payable and Accrued Liabilities*

Included in “Accounts payable and accrued liabilities,” on the accompanying balance sheets, at September 30, 2006 and December 31, 2005 are liabilities of approximately \$9.8 million and \$9.9 million, respectively, representing the amount by which checks issued, but not presented to the Company’s banks for collection, exceeded balances in the applicable disbursement bank accounts.

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

We follow the provisions of SFAS No. 130, “Reporting Comprehensive Income,” which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At September 30, 2006, we recorded \$0.9 million, net of taxes of \$0.6 million, of derivative gains in “Accumulated other comprehensive income (loss), net of income tax” on the accompanying balance sheet. The components of accumulated other comprehensive Income (loss) and related tax effects for 2006 were as follows:

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

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2005	\$ (110,094)	\$ 40,625	\$ (69,469)
Change in fair value of cash flow hedges	(17,520)	6,517	(11,003)
Effect of cash flow hedges settled during the period	1,632,363	(605,404)	1,026,959
Other comprehensive income at September 30, 2006	<u>\$ 1,504,749</u>	<u>\$ (558,262)</u>	<u>\$ 946,487</u>

Total comprehensive income was \$52.2 million and \$27.7 million for the third quarters of 2006 and 2005, respectively. Total comprehensive income was \$127.3 and \$80.5 million for the first nine months of 2006 and 2005, respectively.

*Price-Risk Management Activities*

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

We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. During the third quarters of 2006 and 2005, we recognized a net loss of \$0.4 million relating to our derivative activities. During the first nine months of 2006 and 2005, we recognized a net gain of \$1.6 million and a net loss of \$0.9 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. At September 30, 2006, the Company had recorded \$0.9 million, net of taxes of \$0.6 million, of derivative gains in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The amount of ineffectiveness reported in "Price-risk management and other, net" for the first nine months of 2006 and 2005 were not material. We expect to reclassify all amounts currently held in "Accumulated other comprehensive income (loss), net of income tax" into the statement of income within the next three months when the forecasted sale of hedged production occurs.

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 oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive income (loss), net of income tax." When the hedged transactions are recorded upon the actual sale of oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive income (loss), net of income tax" and recorded in "Price-risk management and other, net" on the accompanying statement of income. The fair value of our derivatives is computed using the Black-Scholes-Merton option pricing model and is periodically verified against quotes from brokers.

At September 30, 2006, we had in place price floors in effect for October 2006 through the December 2006 contract month for oil that cover a portion of our domestic oil production for October 2006 to December 2006. The oil price floors cover notional volumes of 900,000 barrels with a weighted average floor price of \$63.77 per barrel. Our oil price floors in place at September 30, 2006 are expected to cover approximately 45% to

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50% of our estimated domestic oil production from October 2006 to December 2006. The fair value of these instruments at September 30, 2006, was \$2.7 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 \$6.4 million and \$5.8 million in the first nine months of 2006 and 2005, 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 which is included in the full cost pool. This standard requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values. Based on our experience and analysis of the oil and gas services industry, we have not factored a market risk premium into our asset retirement obligation. SFAS No. 143 was adopted by us effective January 1, 2003. The following provides a roll-forward of our asset retirement obligation:

	2006	2005
Asset Retirement Obligation recorded as of January 1	\$ 19,356,367	\$ 17,639,136
Accretion expense for the nine months ended September 30	665,812	565,531
Liabilities incurred for new wells and facilities construction	552,591	63,772
Reductions due to sold, or plugged and abandoned wells	(202,902)	(360,104)
Decrease due to currency exchange rate fluctuations	(21,600)	(27,755)
Asset Retirement Obligation as of September 30	\$ 20,350,268	\$ 17,880,580

At both September 30, 2006 and December 31, 2005, approximately \$0.3 million of our asset retirement obligation is classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying balance sheets.

*New Accounting Pronouncements*

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

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued

### SWIFT ENERGY COMPANY AND SUBSIDIARIES

for accounting changes made in fiscal years beginning after December 15, 2005, and the adoption of this statement had no impact on our financial position or results of operations.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109." This Interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, "Accounting for Income Taxes." FIN No. 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding derecognition, classification and disclosure of these uncertain tax positions. FIN No. 48 is effective for fiscal years beginning after December 15, 2006. The Company has not yet determined what impact, if any, this Interpretation will have on its financial position or results of operations.

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

### **(3) Share-Based Compensation**

We have various types of share-based compensation plans. Refer to Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2005, for additional information related to these share-based compensation plans.

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

Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006 as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized for the nine months ended September 30, 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting the new standard.

As a result of adopting SFAS No. 123R on January 1, 2006, our income before taxes, net income and basic and diluted earnings per share for the three months ended September 30, 2006, were \$0.7 million, \$0.6 million, \$0.02, and \$0.02 lower, respectively, than if we had continued to account for share-based compensation under APB Opinion No. 25 for our stock option grants. For the nine months ended September 30, 2006, income before taxes, net income and basic and diluted earnings per share were \$2.7 million, \$2.2 million, \$0.07, and \$0.07 lower, respectively. Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to one recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in "General and Administrative, net" in the accompanying condensed consolidated statements of operations.

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We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the price at which the stock is sold over the exercise price of the options. In addition, we receive an additional tax deduction when restricted stock vests at a higher value than the value used to recognize compensation expense at the date of grant. Prior to adoption of SFAS No. 123R, we reported all tax benefits resulting from the award of equity instruments as operating cash flows in our condensed consolidated statements of cash flows. In accordance with SFAS No. 123R, we are required to report excess tax benefits from the award of equity instruments as financing cash flows, these benefits totaled \$0.6 million and \$1.5 million for the three and nine months ended September 30, 2006, respectively.

Net cash proceeds from the exercise of stock options were \$3.6 million for the nine months ended September 30, 2006. The actual income tax benefit realized from stock option exercises was \$2.0 million for the same period.

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees is recorded in "General and Administrative, net" in the accompanying condensed consolidated statements of income, and was \$1.8 million and \$0.6 million for the quarter ended September 30, 2006 and 2005, respectively. Stock compensation expense for the nine months ended September 30, 2006, and 2005 was \$5.1 million and \$1.0 million. We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

The following table illustrates the effect on September 30, 2005 operating results and per share information had the Company accounted for share-based compensation in accordance with SFAS No. 123R. Our net income and earnings per share would have been adjusted to the following pro forma amounts:

		<b>Three Months Ended September 30, 2005</b>	<b>Nine Months Ended September 30, 2005</b>
		<u>                    </u>	<u>                    </u>
Net Income:	As Reported	\$27,506,899	\$81,077,709
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	<u>(995,399)</u>	<u>(2,968,488)</u>
	Pro Forma	\$26,511,500	\$78,109,221
Basic EPS:	As Reported	\$.96	\$2.86
	Pro Forma	\$.93	\$2.75
Diluted EPS:	As Reported	\$.92	\$2.77
	Pro Forma	\$.89	\$2.67

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SWIFT ENERGY COMPANY AND SUBSIDIARIES

*Stock Options*

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

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
Dividend yield	0%	0%	0%	0%
Expected volatility	39.1%	41.2%	39.5%	42.5%
Risk-free interest rate	4.8%	3.9%	4.9%	3.8%
Expected life of options (in years)	2.6	3.9	5.6	3.5
Weighted-average grant-date fair value	\$ 12.20	\$ 15.92	\$ 19.31	\$ 10.64

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

At September 30, 2006, there was \$3.6 million of unrecognized compensation cost related to stock options which is expected to be recognized over a weighted-average period of 1.6 years.

The following table represents stock option activity for the nine months ended September 30, 2006:

	September 30, 2006		
	Shares	Wtd. Avg. Exer. Price	Wtd. Avg. Contract Life
Options outstanding, beginning of period	2,118,179	\$ 21.28	
Options granted	164,303	\$ 43.56	
Options canceled	(51,578)	\$ 22.29	
Options exercised	(239,035)	\$ 19.97	
Options outstanding, end of period	<u>1,991,869</u>	\$ 23.25	<u>5.4 Yrs</u>
Options exercisable, end of period	<u>1,182,688</u>	\$ 22.71	<u>4.1 Yrs</u>

The aggregate intrinsic value of options outstanding at September 30, 2006 was \$37.6 million, and the aggregate intrinsic value of options exercisable was \$22.6 million. Total intrinsic value of options exercised was \$5.4 million for the nine months ended September 30, 2006.

*Restricted Stock*

The plans, as described in Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2005, allow for the issuance of restricted stock awards that may not be sold or otherwise transferred until certain restrictions have lapsed. The unrecognized compensation cost related to these awards is expected to be expensed over the period the restrictions lapse (generally one to five years).

The compensation expense for these awards was determined based on the market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of September 30, 2006, we have unrecognized compensation expense of approximately \$15.0 million associated with these awards which are expected to be recognized over a weighted-average period of 2.4 years.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued  
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The following table represents restricted stock activity for the nine months ended September 30, 2006:

	September 30, 2006	
	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	236,950	\$ 34.79
Restricted shares granted	310,956	\$ 43.25
Restricted shares canceled	(21,530)	\$ 38.90
Restricted shares vested	(35,776)	\$ 24.57
Restricted shares outstanding, end of period	490,600	\$ 39.98

**(4) Earnings Per Share**

Basic earnings per share (“Basic EPS”) have been computed using the weighted average number of common shares outstanding during the respective periods. Diluted earnings per share (“Diluted EPS”) for all periods also assumes, as of the beginning of the period, exercise of stock options and restricted stock grants to employees using the treasury stock method. Certain of our stock options, that could potentially dilute Basic EPS in the future, were antidilutive for periods ended September 30, 2006 and 2005, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the periods ended September 30, 2006 and 2005:

	Three Months Ended September 30,					
	2006			2005		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
<b>Basic EPS:</b>						
Net Income and Share Amounts.....	\$ 50,811,567	29,251,945	\$ 1.74	\$ 27,506,899	28,632,895	\$ 0.96
Dilutive Securities:						
Restricted Stock .....	---	130,905		---	71,815	
Stock Options .....	---	801,025		---	1,081,254	
<b>Diluted EPS:</b>						
Net Income and Assumed Share Conversions .....	\$ 50,811,567	30,183,875	\$ 1.68	\$ 27,506,899	29,785,964	\$ 0.92

	Nine Months Ended September 30,					
	2006			2005		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
<b>Basic EPS:</b>						
Net Income and Share Amounts....	\$ 126,294,521	29,161,278	\$ 4.33	\$ 81,077,709	28,390,120	\$ 2.86
Dilutive Securities:						
Restricted Stock .....	---	124,528		---	37,194	
Stock Options .....	---	777,587		---	866,822	
<b>Diluted EPS:</b>						
Net Income and Assumed Share Conversions .....	\$ 126,294,521	30,063,393	\$ 4.20	\$ 81,077,709	29,294,136	\$ 2.77

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Options to purchase approximately 2.0 million shares at an average exercise price of \$23.25 were outstanding at September 30, 2006, while options to purchase 2.4 million shares at an average exercise price of \$20.24 were outstanding at September 30, 2005. Approximately 1.6 million and less than 0.1 million stock options and non-vested shares of restricted stock were not included in the computation of Diluted EPS for the three-month periods ended September 30, 2006, and 2005, respectively, and 1.6 million and 0.2 million options and non-vested shares of restricted stock were not included in the computation of Diluted EPS for the nine-month periods ended September 30, 2006, and 2005, respectively, because these options were antidilutive in that the option price was greater than the average closing market price for the common shares during those periods.

**(5) Long-Term Debt**

Our long-term debt, including the current portion, as of September 30, 2006 and December 31, 2005, was as follows (in thousands):

	<b>September 30, 2006</b>	<b>December 31, 2005</b>
Bank Borrowings .....	\$ ---	\$ ---
7-5/8% senior notes due 2011 .....	150,000	150,000
9-3/8% senior subordinated notes due 2012 ...	200,000	200,000
Long-Term Debt .....	\$ 350,000	\$ 350,000

*Bank Borrowings*

At September 30, 2006, we had no outstanding borrowings under our \$400.0 million credit facility with a syndicate of ten banks that had a borrowing base of \$250.0 million and expires in October 2008. The interest rate is either (a) the lead bank's prime rate (8.25% at September 30, 2006) or (b) the adjusted London Interbank Offered Rate ("LIBOR") plus the applicable margin depending on the level of outstanding debt. The applicable margin is based on the ratio of the outstanding balance to the last calculated borrowing base. On October 2, 2006, we increased the credit facility amount by \$100.0 million to \$500.0 million, and extended the expiration date by roughly three years to October 3, 2011 from October 1, 2008, see footnote eight "Subsequent Events."

The terms of our credit facility at September 30, 2006, 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 amount is re-determined at least every six months and was increased by our bank group to \$250.0 million effective October 2, 2006, at our request from \$150 million. Under the terms of the credit facility, we can increase this commitment amount to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. The next scheduled borrowing base review is on May 1, 2007.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled \$0.2 million for each of the three month period ended September 30, 2006 and 2005, and \$0.6 million and \$0.8 million for the nine month period ended September 30, 2006 and 2005. The amount of commitment fees included in interest expense, net was \$0.1 million for each of the three month period ended September 30, 2006 and 2005, and \$0.4 million for each of the nine months ended September 30, 2006 and 2005.

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

### *Senior Notes Due 2011*

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

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled \$3.0 million for both the three months ended September 30, 2006 and 2005, respectively, and \$8.9 million for each of the nine months ended September 30, 2006 and 2005, 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 each of the three month periods ended September 30, 2006 and 2005, and \$14.4 million for each of the nine month periods ended September 30, 2006 and 2005.

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

We have capitalized interest on our unproved properties in the amount of \$2.2 million and \$1.8 million for the three month periods ended September 30, 2006 and 2005, respectively, and \$6.6 million and \$5.3 million for the nine month periods ended September 30, 2006 and 2005, respectively.

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**(6) Foreign Activities**

As of September 30, 2006, our gross capitalized oil and gas property costs in New Zealand totaled approximately \$340.3 million. Approximately \$324.9 million has been included in the "Proved properties" portion of our oil and gas properties, while \$15.4 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 \$266.4 million at September 30, 2006.

**(7) Acquisitions and Dispositions**

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

In April 2006, we sold our minority interests in the Brookeland and Masters Creek natural gas processing plants for approximately \$20.3 million in cash. Under the "full-cost" method of accounting for oil and gas property and equipment costs, the proceeds of this sale were applied against our oil and gas properties and equipment balance, and no gain or loss was recognized on this transaction.

**(8) Subsequent Events**

In October 2006, we acquired interests in five South Louisiana fields from BP America Production Company. The total price for these interests was approximately \$169 million. The property interests are located primarily in: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), High Island field in Cameron Parish and Bayou Penchant field in Terrebonne Parish. We have recorded \$17.5 million in "Other current assets" at September 30, 2006 related to the deposit for this acquisition. In addition, we have acquired virtually all of the outstanding interest in the South Bearhead Creek field, located in Beaufort Parish, Louisiana, for approximately \$4.5 million in November 2006.

In October 2006, we settled all insurance claims with our insurers relating to hurricanes Katrina and Rita and entered into a confidential final settlement agreement. The receipt of these amounts is expected to result in a benefit of \$7.7 million in the fourth quarter of 2006, for the portion of the above referenced settlement, which we have determined to be non-property damage related claims, based on internal calculations.

On October 2, 2006, we increased the credit facility amount by \$100.0 million to \$500.0 million, and extended the expiration date by roughly three years to October 3, 2011 from October 1, 2008. The other terms of the credit facility, including the borrowing base amount and commitment amount, stayed substantially the same. Certain of the covenants imposed by this credit facility were amended with the extension of the facility to be less restrictive on various corporate actions and are discussed below. The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed \$15.0 million in any fiscal year which increased from \$5.0 million), a remaining aggregate limitation on purchases of our stock of \$50.0 million which increased from \$15.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on

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incurring other debt or repurchasing our 7-5/8% senior notes due 2011 or 9-3/8% senior subordinated notes due 2012. The borrowing base amount is re-determined at least every six months and was increased by our bank group to \$250.0 million effective October 2, 2006, at our request from \$150 million.

**(9) Condensed Consolidating Financial Information**

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

Condensed Consolidating Balance Sheets

(in 000's)

	September 30, 2006				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
<b>ASSETS</b>					
Current assets	\$ ---	\$ 191,681	\$ 20,681	\$ ---	\$ 212,362
Property and equipment	---	972,444	242,273	---	1,214,717
Investment in subsidiaries (equity method)	750,275	---	544,086	(1,294,361)	---
Other assets	---	41,187	655	(32,417)	9,424
Total assets	<u>\$ 750,275</u>	<u>\$ 1,205,312</u>	<u>\$ 807,695</u>	<u>\$ (1,326,778)</u>	<u>\$ 1,436,503</u>
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>					
Current liabilities	\$ ---	\$ 103,274	\$ 14,279	\$ ---	\$ 117,553
Long-term liabilities	---	557,951	43,141	(32,417)	568,675
Stockholders' equity	750,275	544,086	750,275	(1,294,361)	750,275
Total liabilities and stockholders' equity	<u>\$ 750,275</u>	<u>\$ 1,205,312</u>	<u>\$ 807,695</u>	<u>\$ (1,326,778)</u>	<u>\$ 1,436,503</u>

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

(in 000's)

December 31, 2005

	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
<b>ASSETS</b>					
Current assets	\$ ---	\$ 92,788	\$ 22,267	\$ ---	\$ 115,055
Property and equipment	---	862,717	216,316	---	1,079,034
Investment in subsidiaries (equity method)	607,318	---	410,612	(1,017,930)	---
Other assets	---	31,955	682	(22,313)	10,324
Total assets	<u>\$ 607,318</u>	<u>\$ 987,460</u>	<u>\$ 649,877</u>	<u>\$ (1,040,243)</u>	<u>\$ 1,204,413</u>
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>					
Current liabilities	\$ ---	\$ 85,472	\$ 12,949	\$ ---	\$ 98,421
Long-term liabilities	---	491,376	29,610	(22,313)	498,674
Stockholders' equity	607,318	410,612	607,318	(1,017,930)	607,318
Total liabilities and stockholders' equity	<u>\$ 607,318</u>	<u>\$ 987,460</u>	<u>\$ 649,877</u>	<u>\$ (1,040,243)</u>	<u>\$ 1,204,413</u>

Condensed Consolidating Statements of Income

(in 000's)

Three Months Ended September 30, 2006

	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	\$ ---	\$ 153,279	\$ 20,179	\$ ---	\$ 173,459
Expenses	---	77,409	13,841	---	91,250
Income (loss) before the following:	---	75,871	6,338	---	82,209
Equity in net earnings of subsidiaries	50,812	---	46,342	(97,154)	---
Income before income taxes	50,812	75,871	52,681	(97,154)	82,209
Income tax provision (benefit)	---	29,528	1,869	---	31,398
Net income	<u>\$ 50,812</u>	<u>\$ 46,342</u>	<u>\$ 50,812</u>	<u>\$ (97,154)</u>	<u>\$ 50,812</u>

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

(in 000's)

Nine Months Ended September 30, 2006

	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	\$ ---	\$ 406,080	\$ 50,725	\$ ---	\$ 456,805
Expenses	---	218,391	38,241	---	256,631
Income (loss) before the following:	---	187,690	12,484	---	200,174
Equity in net earnings of subsidiaries	126,295	---	116,811	(243,105)	---
Income before income taxes	126,295	187,690	129,295	(243,105)	200,174
Income tax provision (benefit)	---	70,879	3,000	---	73,879
Net income	\$ 126,295	\$ 116,811	\$ 126,295	\$ (243,105)	\$ 126,295

(in 000's)

Three Months Ended September 30, 2005

	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	\$ 81,220	\$ 19,633	\$ ---	\$ 100,853
Expenses	46,057	11,895	---	57,952
Income (loss) before the following:	35,163	7,738	---	42,901
Equity in net earnings of subsidiaries	5,838	---	(5,838)	---
Income before income taxes	41,001	7,738	(5,838)	42,901
Income tax provision (benefit)	13,494	1,900	---	15,394
Net income	\$ 27,507	\$ 5,838	\$ (5,838)	\$ 27,507

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

(in 000's)

	Nine Months Ended September 30, 2005			
	Swift Energy Co. (Parent and			Swift Energy Co.
	Issuer)	Other Subsidiaries	Eliminations	Consolidated
Revenues	\$ 246,946	\$ 53,830	\$ (2)	\$ 300,774
Expenses	141,940	34,398	(2)	176,336
Income (loss) before the following:	105,006	19,432	---	124,438
Equity in net earnings of subsidiaries	15,346	---	(15,346)	---
Income before income taxes	120,352	19,432	(15,346)	124,438
Income tax provision (benefit)	39,274	4,086	---	43,360
Net income	\$ 81,078	\$ 15,346	\$ (15,346)	\$ 81,078

Condensed Consolidating Statements of Cash Flows

(in 000's)

	Nine Months Ended September 30, 2006				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
	Cash flow from operations	\$ ---	\$ 281,570	\$ 29,113	\$ ---
Cash flow from investing activities	---	(237,602)	(46,844)	10,105	(274,342)
Cash flow from financing activities	---	5,773	10,105	(10,105)	5,773
Net increase in cash	---	49,740	(7,627)	---	42,113
Cash, beginning of period	---	44,911	8,094	---	53,005
Cash, end of period	\$ ---	\$ 94,651	\$ 467	\$ ---	\$ 95,118

(in 000's)

	Nine Months Ended September 30, 2005			
	Swift Energy Co. (Parent and			Swift Energy Co.
	Issuer)	Other Subsidiaries	Eliminations	Consolidated
Cash flow from operations	\$ 184,254	\$ 36,206	\$ ---	\$ 220,460
Cash flow from investing activities	(129,713)	(33,896)	5,284	(158,325)
Cash flow from financing activities	(1,171)	5,284	(5,284)	(1,171)
Net increase (decrease) in cash	53,370	7,594	---	60,964
Cash, beginning of period	205	4,715	---	4,920
Cash, end of period	\$ 53,575	\$ 12,309	\$ ---	\$ 65,884

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

**(10) Segment Information**

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

	<b>Three Months Ended September 30,</b>					
	<b>2006</b>			<b>2005</b>		
	<b>Domestic</b>	<b>New Zealand</b>	<b>Total</b>	<b>Domestic</b>	<b>New Zealand</b>	<b>Total</b>
Oil and gas sales	\$ 153,754,146	\$ 19,614,403	\$ 173,368,549	\$ 81,692,754	\$ 19,314,770	\$ 101,007,524
Costs and Expenses:						
Depreciation, depletion and amortization	37,619,396	8,248,319	45,867,715	17,328,183	6,542,104	23,870,287
Accretion of asset retirement obligation	133,846	37,699	171,545	157,442	34,087	191,529
Lease operating costs	9,620,102	3,306,008	12,926,110	8,903,988	3,317,165	12,221,153
Severance and other taxes	17,251,643	1,238,195	18,489,838	8,438,368	1,232,197	9,670,565
Income from oil and gas operations	\$ 89,129,159	\$ 6,784,182	\$ 95,913,341	\$ 46,864,773	\$ 8,189,217	\$ 55,053,990
Price-risk management and other, net			90,303			(154,019)
General and administrative, net			8,018,260			5,803,946
Interest expense, net			5,776,220			6,194,370
Income Before Income Taxes			<u>\$ 82,209,164</u>			<u>\$ 42,901,655</u>

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

	Nine Months Ended September 30,					
	2006			2005		
	Domestic	New Zealand	Total	Domestic	New Zealand	Total
Oil and gas sales	\$ 403,128,509	\$ 50,187,010	\$ 453,315,519	\$ 248,399,764	\$ 53,051,493	\$ 301,451,257
Costs and Expenses:						
Depreciation, depletion and amortization	97,613,811	22,537,635	120,151,446	57,560,343	19,292,953	76,853,296
Accretion of asset retirement obligation	555,002	110,810	665,812	465,465	100,066	565,531
Lease operating costs	36,341,501	9,502,147	45,843,648	25,651,928	9,183,230	34,835,158
Severance and other taxes	45,957,658	3,253,056	49,210,714	26,197,345	3,385,055	29,582,400
Income from oil and gas Operations	\$ 222,660,537	\$ 14,783,362	\$ 237,443,899	\$ 138,524,683	\$ 21,090,189	\$ 159,614,872
Price-risk management and other, net			3,489,510			(677,143)
General and administrative, net			23,323,223			15,674,141
Interest expense, net			17,436,326			18,825,273
Income Before Income Taxes			\$ 200,173,860			\$ 124,438,315
Total Assets	\$ 1,197,620,135	\$ 238,882,977	\$ 1,436,503,112	\$ 886,525,732	\$ 239,968,842	\$ 1,126,494,574

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

**ITEM 2.**

*You should read the following discussion and analysis in conjunction with our financial information and our condensed consolidated financial statements and notes thereto included in this report and our Annual Report on Form 10-K for the year ended December 31, 2005. The following information contains forward-looking statements. For a discussion of limitations inherent in forward-looking statements, see "Forward-Looking Statements" on page 39 of this report.*

**Overview**

Swift Energy had record net income, revenues, and production for the third quarter 2006. Net income increased 85% to \$50.8 million, revenues increased 72% to \$173.5 million, and production increased 39% to 18.8 Bcfe, all as compared to the hurricane-affected third quarter 2005 levels. For the nine months ended September 30, 2006, net income increased 56% to \$126.3 million, revenues increased 52% to \$456.8 million, and production increased 15% to 51.6 Bcfe, all as compared to the same period in 2005. The continued strong crude oil prices, increases in our domestic production, and our recovery from the hurricanes of 2005 contributed to these record increases. As a result of our domestic production increases, 71% of our third quarter production was liquid hydrocarbons, of which 64% was crude oil and 7% was natural gas liquids.

New Zealand produced 3.5 Bcfe in the third quarter of 2006, a 19% decrease from the same period in 2005. During the third quarter of 2006, we were successful on one of three wells drilled in New Zealand and suspended operations on another.

Our production in the Lake Washington Field averaged more than 18,500 net barrels of oil per day during the third quarter of 2006, achieving our year-end exit rate goal ahead of plan. We successfully completed 11 of 14 wells in the third quarter of 2006, including 9 of 11 domestic development wells drilled for a success rate of 82% for the quarter. As a result of activity-to-date, as well as our recent Louisiana acquisitions, we are increasing our 2006 annual production guidance to a range of 70.0 to 71.0 Bcfe from our previous guidance range of 68.8 to 70.5 Bcfe.

Our overall costs and expenses continued to increase during the third quarter of 2006, as have costs across our sector due to tight industry conditions. These increases were in line with our expectations, excluding the insurance reimbursements as a result of the settlement during the third quarter of our insurance claims due to Hurricanes Katrina and Rita, the proceeds of which have not all been received. These costs also increased as a result of our workforce expansion and expensing of stock compensation. We expect cost pressures to continue to affect the industry for the remainder of 2006.

A primary focus this year has been capitalizing on the geologic and geophysical efforts that have become evident with some of our recent successes, particularly at the Newport area in Lake Washington. We expect the first set of our pre-stack depth migration of our Lake Washington 3-D data to be completed in the fourth quarter of 2006, which will help us understand Newport's deeper potential as well as the deeper horizons in Lake Washington. We are widening our focus on activity at Bay de Chene and Cote Blanche Island, which helps confirm our seismic interpretation and should also help further define similar opportunities in other fault blocks surrounding the salt feature in Bay De Chene. The 3-D seismic shoot in Cote Blanche Island was completed early in the third quarter of 2006 and is now being processed. We expect to begin benefiting from this new data with our drilling program in Cote Blanche Island during the second half of 2007.

Very early in the fourth quarter of 2006, we closed on several strategic acquisitions of interests in five additional fields in South Louisiana and the consolidation of almost 100% of the working interests in our South Bearhead Creek Field for approximately \$169 million and \$4.5 million, respectively. We believe these transactions add strategic anchor assets in a very productive fairway that should benefit us and our stakeholders for many years to come.

Since the end of the third quarter, we have accessed our line of credit under our credit facility to help fund acquisition activity, along with cash on hand. Early in the fourth quarter of 2006, we also increased our credit facility to \$500 million from \$400 million and extended it about three years to October 3, 2011.

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

Our drilling program for the remainder of 2006 is to drill 4 additional wells in the Lake Washington area, 5 additional wells in Bay de Chene, with at least 2 wells in Bay de Chene being potential high impact exploration wells with results expected in 2007. In New Zealand, plans are underway to complete the Goss well in the Tikorangi formation for testing and evaluation. We are in the midst of our 2007 capital planning and are using a conservative price deck relative to commodity prices with the continued goal of conducting operations within our cash flow. Crude oil and natural gas prices have receded somewhat from the record highs earlier in 2006 but still remain strong, particularly with respect to crude oil.

This year is shaping up to be a year of accomplishment for Swift Energy. We have strengthened our balance sheet. We have built a large regional 3-D seismic database that has enabled us to create the most significant portfolio of prospects in Swift Energy's history. Our staff has been executing and delivering on our strategic plan, which has led to significant production growth. In the fourth quarter of 2006, our South Louisiana drilling program will continue to target potentially high impact exploration prospects and the Company will begin integrating the additional five fields we acquired in South Louisiana, all of which are covered by our 3-D seismic database. As Swift Energy concludes the execution of our 2006 plan, we believe our activity and results will lead to further visible value creation for our shareholders.

**Results of Operations – Three Months Ended September 30, 2006 and 2005**

**Revenues.** Our revenues in the third quarter of 2006 increased by 72% compared to revenues in the same period in 2005, due primarily to an increase in commodity prices and the production increase principally from our Lake Washington field and reduced third quarter of 2005 volumes as a result of the hurricanes. Revenues from our oil and gas sales comprised substantially all of net revenues for the third quarter of 2006 and 2005. In the third quarter of 2006, oil production made up 64% of total production, natural gas made up 29%, and NGL represented 7%. In the third quarter of 2005, oil production made up 47% of total production, natural gas made up 44%, and NGL represented 9%. The percentage of our total production from oil increased as Lake Washington production, which is predominantly oil, increased over third quarter of 2005 levels.

Our third quarter 2006 weighted average prices increased 24% to \$9.24 per Mcfe from \$7.48 in the third quarter of 2005, with oil prices appreciating 17% to \$69.62 from \$59.66, natural gas prices decreasing 8% to \$4.87 from \$5.29, and NGL prices rising 14% to \$36.18 from \$31.84.

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

The following table provides additional information regarding the changes in the sources of our oil and gas sales and volumes for the periods ended September 30, 2006 and 2005:

<u>Area</u>	<u>Three Months Ended September 30,</u>			
	<u>Oil and Gas Sales (In Millions)</u>		<u>Net Oil and Gas Sales Volumes (Bcfe)</u>	
	<u>2006</u>	<u>2005</u>	<u>2006</u>	<u>2005</u>
AWP Olmos .....	\$ 13.4	\$ 16.5	1.9	2.0
Brookeland .....	4.7	6.5	0.6	0.8
Lake Washington .....	116.1	46.6	10.5	4.9
Masters Creek .....	3.3	4.5	0.4	0.5
Other .....	16.3	7.6	1.8	0.9
Total Domestic .....	\$ 153.8	\$ 81.7	15.2	9.1
Rimu/Kauri .....	12.1	11.3	1.7	2.2
TAWN .....	7.5	8.0	1.8	2.2
Total New Zealand ...	\$ 19.6	\$ 19.3	3.5	4.4
Total .....	\$ 173.4	\$ 101.0	18.8	13.5

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

	<u>Sales Volume</u>				<u>Average Sales Price</u>		
	<u>Oil (MBbl)</u>	<u>NGL (MBbl)</u>	<u>Gas (Bcf)</u>	<u>Combined (Bcfe)</u>	<u>Oil (Bbl)</u>	<u>NGL (Bbl)</u>	<u>Gas (Mcf)</u>
<b><u>2006</u></b>							
Three Months Ended September 30:							
Domestic .....	1,824	159	3.3	15.2	\$69.54	\$42.37	\$6.07
New Zealand .....	168	61	2.2	3.5	\$70.49	\$20.09	\$3.04
Total .....	1,992	220	5.5	18.8	\$69.62	\$36.18	\$4.87
<b><u>2005</u></b>							
Three Months Ended September 30:							
Domestic .....	925	119	2.8	9.1	\$59.44	\$40.58	\$7.68
New Zealand .....	134	85	3.1	4.4	\$61.23	\$19.50	\$3.08
Total .....	1,059	204	5.9	13.5	\$59.66	\$31.84	\$5.29

In the third quarter of 2006, our \$72.4 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a \$18.5 million favorable impact on sales, of which \$19.8 million was attributable to the 17% increase in average oil prices received, \$1.0 million was attributable to the 14% increase in average NGL prices received, offset by \$2.3 million of decreases attributable to the 8% decrease in average gas prices received; and
- Volume variances that had a \$53.9 million favorable impact on sales, with \$55.7 million of increases coming from the 933,000 Bbl increase in oil sales volumes, \$0.5 million of increases attributable to the 16,000 Bbl increase in NGL sales volumes, offset by \$2.3 million of decreases due to the 0.4 Bcf decrease in gas sales volumes.

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

**Costs and Expenses.** Our expenses in the third quarter of 2006 increased \$33.3 million, or 57%, compared to expenses in the same period of 2005. The increase was due to a \$22.0 million increase in DD&A as our production and depletable oil and gas property base increased, an \$8.8 million increase in severance and other taxes due to increased production volumes and higher commodity prices in the third quarter of 2006, and a \$2.2 million increase in net general and administrative expenses.

Our third quarter 2006 general and administrative expenses, net, increased \$2.2 million, or 38%, from the level of such expenses in the same 2005 period. This increase was primarily due to an expansion of our workforce and an increase in stock compensation expense resulting from the adoption of SFAS No. 123R. Our stock compensation expense recorded in general and administrative, net, increased by \$1.2 million, net of capitalized amounts, over third quarter of 2005 levels. For the third quarters of 2006 and 2005, our capitalized general and administrative costs, including capitalized stock compensation, totaled \$8.1 million and \$4.6 million, respectively. Our capitalized general and administrative expenses increased due to the expansion of our workforce and the capitalization of stock compensation related to the geological and geophysical workforce. Our net general and administrative expenses per Mcfe produced were \$0.43 per Mcfe in the third quarters of both 2006 and 2005. The portion of supervision fees recorded as a reduction to general and administrative expenses was \$2.2 million for the third quarter of 2006 and \$2.0 million for the 2005 period.

DD&A increased \$22.0 million, or 92%, in the third quarter of 2006 from the level of those expenses in the same period of 2005. Domestically, DD&A increased \$20.3 million in the third quarter of 2006 due to increases in the depletable oil and gas property base, including future development costs and higher production in the 2006 period. In New Zealand, DD&A increased by \$1.7 million in the third quarter of 2006 due to increases in the depletable oil and gas property base and lower reserves volumes, partially offset by lower production in the 2006 period. Our DD&A rate per Mcfe of production was \$2.45 and \$1.77 in the third quarters of 2006 and 2005, respectively.

We recorded \$0.2 million of accretions to our asset retirement obligation in both the third quarters of 2006 and 2005.

Our lease operating costs in the third quarter of 2006 increased \$0.7 million, or 6%, over the level of such expenses in the same 2005 period. Almost all of the increase was related to our domestic operations, which increased primarily due to higher production from our South Louisiana area and higher insurance costs. Offsetting the increase in costs and reducing the lease operating cost per Mcfe, was recording of a reduction in lease operating expense of \$2.8 million related to the settlement of insurance claims from hurricanes Katrina and Rita in the third quarter of 2006. Our lease operating costs in New Zealand were \$3.3 million in both the third quarters of 2006 and 2005, respectively. Our lease operating costs per Mcfe produced were \$0.69 in the third quarter of 2006 and \$0.91 in the third quarter of 2005. Higher production volumes in the third quarter of 2006 over the third quarter of 2005 decreased the cost per Mcfe in the 2006 period.

In the third quarter of 2006, severance and other taxes increased \$8.8 million, or 91%, over levels in the third quarter of 2005. The increase was due primarily to higher commodity prices and increased Lake Washington production. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than 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 10.7% and 9.6% in the third quarters of 2006 and 2005, respectively.

Our total interest cost in the third quarter of 2006 was \$8.0 million, of which \$2.2 million was capitalized. Our total interest cost in the third quarter of 2005 was also \$8.0 million, of which \$1.8 million was capitalized. We capitalize a portion of interest related to unproved properties. The decrease of interest expense in the third quarter of 2006 was primarily attributable to higher capitalized costs.

Our overall effective tax rate was 38.2% in the third quarter of 2006 and 35.9% in the third quarter of 2005. The effective income tax rate for the third quarter of 2006 was higher than the U.S. statutory rate primarily due to state income taxes, an unfavorable rate impact for non-deductible stock compensation, and

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

was partially offset by reductions from the New Zealand statutory rate attributable to the currency effect on the New Zealand deferred tax calculation. The third quarter of 2005 rate is lower due to a favorable correction in the New Zealand basis of oil and gas properties.

**Net Income.** For the third quarter of 2006, our net income of \$50.8 million was 85% higher, and Basic EPS of \$1.74 was 81% higher, than our third quarter of 2005 net income of \$27.5 million and Basic EPS of \$0.96. Our Diluted EPS in the third quarter of 2006 of \$1.68 was 82% higher than our third quarter 2005 Diluted EPS of \$0.92. These higher amounts are due to our increased oil and gas revenues, which in turn were higher due to continued strong commodity prices and increased production during the third quarter of 2006.

**Results of Operations – Nine Months Ended September 30, 2006 and 2005**

**Revenues.** Our revenues in the first nine months of 2006 increased by 52% compared to revenues in the same period in 2005, due primarily to an increase in commodity prices and the production increase principally from our Lake Washington field. Revenues from our oil and gas sales comprised substantially all of net revenues for the first nine months of 2006 and 2005. In the first nine months of 2006, oil production made up 61% of total production volumes, natural gas made up 33%, and NGL represented 6%. In the first nine months of 2005, oil production made up 51% of total production volumes, natural gas made up 41%, and NGL represented 8%. The percentage of our total production from oil increased as Lake Washington production, which is predominantly oil, increased over 2005 levels.

Our first nine months of 2006 weighted average prices increased 31% to \$8.78 per Mcfe from \$6.71 in the first nine months of 2005, with oil prices appreciating 29% to \$66.92 from \$51.99, natural gas prices increasing 6% to \$5.02 from \$4.73, and NGL prices rising 20% to \$32.69 from \$27.15.

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

The following table provides additional information regarding the changes in the sources of our oil and gas sales and volumes for the nine months ended September 30, 2006 and 2005:

<u>Area</u>	<u>Nine Months Ended September 30,</u>			
	<u>Oil and Gas Sales (In Millions)</u>		<u>Net Oil and Gas Sales Volumes (Bcfe)</u>	
	<u>2006</u>	<u>2005</u>	<u>2006</u>	<u>2005</u>
AWP Olmos .....	\$ 42.0	\$ 40.7	5.6	5.7
Brookeland .....	12.3	14.6	1.6	2.2
Lake Washington .....	300.7	160.1	28.3	19.5
Masters Creek .....	10.8	13.6	1.3	2.0
Other .....	37.3	19.4	4.3	2.6
Total Domestic .....	<u>\$ 403.1</u>	<u>\$ 248.4</u>	<u>41.1</u>	<u>32.0</u>
Rimu/Kauri .....	29.6	33.1	5.0	6.5
TAWN .....	20.6	20.0	5.5	6.4
Total New Zealand ....	<u>\$ 50.2</u>	<u>\$53.1</u>	<u>10.5</u>	<u>12.9</u>
Total .....	<u>\$ 453.3</u>	<u>\$ 301.5</u>	<u>51.6</u>	<u>44.9</u>

The following table provides additional information regarding our oil and gas sales for the nine months ended September 30, 2006 and 2005:

	<u>Sales Volume</u>				<u>Average Sales Price</u>		
	<u>Oil (MBbl)</u>	<u>NGL (MBbl)</u>	<u>Gas (Bcf)</u>	<u>Combined (Bcfe)</u>	<u>Oil (Bbl)</u>	<u>NGL (Bbl)</u>	<u>Gas (Mcf)</u>
<b><u>2006</u></b>							
Nine Months Ended September 30:							
Domestic .....	4,866	319	10.0	41.1	\$66.75	\$41.29	\$6.53
New Zealand .....	373	191	7.1	10.5	\$69.13	\$18.29	\$2.92
Total .....	<u>5,239</u>	<u>510</u>	<u>17.1</u>	<u>51.6</u>	<u>\$66.92</u>	<u>\$32.69</u>	<u>\$5.02</u>
<b><u>2005</u></b>							
Nine Months Ended September 30:							
Domestic .....	3,448	381	9.1	32.0	\$51.65	\$32.66	\$6.38
New Zealand .....	358	255	9.2	12.9	\$55.25	\$18.90	\$3.10
Total .....	<u>3,806</u>	<u>636</u>	<u>18.3</u>	<u>44.9</u>	<u>\$51.99</u>	<u>\$27.15</u>	<u>\$4.73</u>

In the first nine months of 2006, our \$151.9 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a \$86.2 million favorable impact on sales, of which \$78.3 million was attributable to the 29% increase in average oil prices received, \$5.1 million was attributable to the 6% increase in average gas prices received, and \$2.8 million was attributable to the 20% increase in average NGL prices received; and
- Volume variances that had a \$65.7 million favorable impact on sales, with \$74.5 million of increases coming from the 1,433,000 Bbl increase in oil sales volumes, offset by \$5.4 million of decreases due to the 1.1 Bcf decrease in gas sales volumes, and \$3.4 million of decreases attributable to the 126,000 Bbl decrease in NGL sales volumes.

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

**Costs and Expenses.** Our expenses in the first nine months of 2006 increased \$80.3 million, or 46%, compared to expenses in the same period of 2005. The increase was due to a \$43.3 million increase in DD&A as our production and depletable oil and gas property base increased, a \$19.6 million increase in severance and other taxes due to increased production volumes and higher commodity prices in 2006, and an \$11.0 million increase in lease operating costs due to higher production and hurricane repair costs.

Our first nine months of 2006 general and administrative expenses, net, increased \$7.6 million, or 49%, from the level of such expenses in the same 2005 period. This increase was primarily due to an expansion of our workforce and an increase in stock compensation expense resulting from the adoption of SFAS No. 123R. Our stock compensation expense recorded in general and administrative, net, increased by \$3.9 million, net of capitalized amounts, over the first nine months of 2005. For the nine months of 2006 and 2005, our capitalized general and administrative costs, including capitalized stock compensation, totaled \$20.7 million and \$13.4 million, respectively. Our capitalized general and administrative expenses increased due to the expansion of our workforce and the capitalization of stock compensation related to the geological and geophysical workforce. Our net general and administrative expenses per Mcfe produced increased to \$0.45 per Mcfe in the first nine months of 2006 from \$0.35 per Mcfe in the same 2005 period. The portion of supervision fees recorded as a reduction to general and administrative expenses was \$6.4 million for the first nine months of 2006 and \$5.8 million for the 2005 period.

DD&A increased \$43.3 million, or 56%, in the first nine months of 2006 from the level of those expenses in the same period of 2005. Domestically, DD&A increased \$40.1 million in the first nine months of 2006 due to increases in the depletable oil and gas property base, including future development costs, and higher production in the 2006 period. In New Zealand, DD&A increased by \$3.2 million in the first nine months of 2006 due to increases in the depletable oil and gas property base and lower reserves volumes, partially offset by lower production in the 2006 period. Our DD&A rate per Mcfe of production was \$2.33 and \$1.71 in the first nine months of 2006 and 2005, respectively.

We recorded \$0.7 million and \$0.6 million of accretions to our asset retirement obligation in the first nine months of 2006 and 2005, respectively.

Our lease operating costs in the first nine months of 2006 increased \$11.0 million, or 32%, over the level of such expenses in the same 2005 period. Almost all of the increase was related to our domestic operations, which increased primarily due to higher production from our South Louisiana area and higher insurance costs. Our lease operating costs in New Zealand increased in the first nine months of 2006 by \$0.3 million due to planned maintenance work. Our lease operating costs per Mcfe produced were \$0.89 in the first nine months of 2006 and \$0.78 in the first nine months of 2005.

In the first nine months of 2006, severance and other taxes increased \$19.6 million, or 66%, over levels in the first nine months of 2005. The increase was due primarily to higher commodity prices and increased Lake Washington production. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than 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 10.9% and 9.8% in the first nine months of 2006 and 2005, respectively.

Our total interest cost in the first nine months of 2006 was \$24.0 million, of which \$6.6 million was capitalized. Our total interest cost in the first nine months 2005 was \$24.1 million, of which \$5.3 million was capitalized. We capitalize a portion of interest related to unproved properties. The decrease of interest expense in the first nine months of 2006 was primarily attributable to higher capitalized costs.

Our overall effective tax rate was 36.9% and 34.8% in the first nine months of 2006 and 2005, respectively. The effective income tax rate for the first nine months of 2006 was higher than the U.S. statutory rate primarily due to state income taxes, an unfavorable rate impact for non-deductible stock compensation, and was partially offset by reductions from the New Zealand statutory rate attributable to the currency effect on the New Zealand deferred tax calculation. For the first nine months of 2005, the rate was lower due to a

**MANAGEMENT'S DISCUSSION AND ANALYSIS OF  
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favorable correction in the New Zealand basis of oil and gas properties.

**Net Income.** For the first nine months of 2006, our net income of \$126.3 million was 56% higher, and Basic EPS of \$4.33 was 52% higher, than our first nine months of 2005 net income of \$81.1 million and Basic EPS of \$2.86. Our Diluted EPS in the first nine months of 2006 of \$4.20 was 52% higher than our first nine months of 2005 Diluted EPS of \$2.77. These higher amounts are due to our increased oil and gas revenues, which in turn were higher due to continued strong commodity prices and increased production during the first nine months of 2006.

**Share-Based Compensation**

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

Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006 as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized in the nine months ended September 30, 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting the new standard.

As a result of adopting SFAS No. 123R on January 1, 2006, our income before taxes, net income and basic and diluted earnings per share for the three months ended September 30, 2006, were \$0.7 million, \$0.6 million, \$0.02, and \$0.02 lower, respectively, than if we had continued to account for share-based compensation under APB Opinion No. 25 for our stock option grants. For the nine months ended September 30, 2006, income before taxes, net income and basic and diluted earnings per share were \$2.7 million, \$2.2 million, \$0.07, and \$0.07 lower, respectively. Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in "General and Administrative, net" in the accompanying condensed consolidated statements of operations.

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

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
Dividend yield	0%	0%	0%	0%
Expected volatility	39.1%	41.0%	39.5%	42.5%
Risk-free interest rate	4.8%	3.9%	4.9%	3.8%
Expected life of options (in years)	2.6	3.9	5.6	3.5
Weighted-average grant-date fair value	\$ 12.20	\$ 15.92	\$ 19.33	\$ 10.64

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

The expected term has been calculated using the Securities and Exchange Commission Staff's shortcut approach from Staff Accounting Bulletin No. 107. We have analyzed historical volatility and based on analysis of all relevant factors use a three-year period to estimate expected volatility of our stock option grants. We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

At September 30, 2006, there was \$3.6 million of unrecognized compensation cost related to stock options, which are expected to be recognized over a weighted-average period of 1.6 years, and unrecognized compensation expense of \$15.0 million related to restricted stock awards which are expected to be recognized over a weighted-average period of 2.4 years. The compensation expense for restricted stock awards was determined based on the market price of our stock at the date of grant applied to the total numbers of shares that were anticipated to fully vest.

### **Contractual Commitments and Obligations**

We had no material changes in our contractual commitments and obligations from December 31, 2005 amounts referenced under "Contractual Commitments and Obligations" in Management's Discussion and Analysis" in our Annual Report on form 10-K for the period ending December 31, 2005.

### **Commodity Price Trends and Uncertainties**

Oil and natural gas prices historically have been volatile and are expected to continue to be volatile in the future. The price of oil has declined in September 2006 from levels earlier in the year; however, it is currently significantly higher when compared to longer-term historical prices. Factors such as worldwide supply disruptions, worldwide economic conditions, weather conditions, actions taken by OPEC, and fluctuating currency exchange rates can cause wide fluctuations in the price of oil. Domestic natural gas prices continue to remain higher when compared to longer-term historical prices. North American weather conditions, the industrial and consumer demand for natural gas, storage levels of natural gas, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas. Such factors are beyond our control.

### **Income Tax Regulations**

As of September 30, 2006, we believe we have utilized all of our U.S. federal operating loss carryforwards during the 2006 tax year.

The tax laws in the jurisdictions in which we operate continuously change and professional judgments regarding such tax laws can differ. On May 18, 2006 the State of Texas enacted a new tax bill that significantly changes the state's franchise tax, effective January 1, 2007 for calendar year taxpayers. The old franchise tax was computed on both "earned surplus" (based on income and director and officer compensation) and taxable capital. The new franchise tax is computed on "gross margin" (generally based on revenue less costs of goods sold). The Company accounts for the earned surplus portion of the old franchise tax as an income tax. The Company will continue to account for the new franchise tax as an income tax.

The Company has recomputed its Texas income tax expense by applying the franchise tax rules to its current income tax expense and has recalculated its cumulative deferred income tax following the new franchise tax rules. This change did not result in a significant adjustment to the Company's tax rate or its cumulative deferred tax liability.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF  
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**Liquidity and Capital Resources**

During the first nine months of 2006, we relied upon our net cash provided by operating activities of \$310.7 million and proceeds from the sale of property and equipment of \$20.3 million to fund capital expenditures of \$291.3 million. During the first nine months of 2005, we relied upon our net cash provided by operating activities of \$220.5 million to fund capital expenditures of \$158.1 million and to pay down our bank borrowings by \$7.5 million.

**Acquisitions**

In October 2006, we acquired interests in five South Louisiana fields from BP America Production Company. The total price for these interests was approximately \$169 million. The property interests are located primarily in: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), High Island field in Cameron Parish and Bayou Penchant field in Terrebonne Parish. In addition, we have acquired virtually all of the outstanding interest in the South Bearhead Creek field, located in Beauregard Parish, Louisiana, for \$4.5 million in November 2006.

**Net Cash Provided by Operating Activities.** For the first nine months of 2006, our net cash provided by operating activities was \$310.7 million, representing a 41% increase as compared to \$220.5 million generated during the same 2005 period. The \$90.2 million increase in the first nine months of 2006 was primarily due to an increase of \$151.9 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 insurance costs and higher severance taxes due to higher oil and gas revenues.

**Accounts Receivable.** We assess the collectibility of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At both September 30, 2006 and December 31, 2005, we had an allowance for doubtful accounts of less than \$0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying balance sheets. Receivables related to insurance reimbursement are computed in accordance with applicable accounting guidance; and we monitor our costs incurred and their collectibility under our insurance policies and believe all amounts recorded are recoverable.

In October 2006, we settled all insurance claims with our insurers relating to hurricanes Katrina and Rita and entered into a confidential final settlement agreement. Based on an internal calculation, the property damage related amount of the settlement was applied first to offset the previously established insurance accounts receivable and then as a reduction to the appropriate capital and expense categories. The receipt of these amounts in the fourth quarter of 2006 is also expected to result in a benefit of \$7.7 million for the portion of the above referenced settlement, which we have determined to be non-property damage related claims, based on internal calculations.

**Bank Credit Facility.** We had no borrowings under our bank credit facility at September 30, 2006 and December 31, 2005. Our bank credit facility at September 30, 2006 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 October 2, 2006. On October 2, 2006, we increased our revolving line of credit by \$100.0 million, to \$500.0 million, and extended the expiration date by roughly three years to October 3, 2011. Also, on October 2, 2006, we requested that the commitment amount with our bank be increased to \$250 million from \$150 million. 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.

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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 3, 2011. Our \$150.0 million of 7-5/8% senior notes mature July 15, 2011, and our \$200.0 million of 9-3/8% senior subordinated notes mature May 1, 2012.

**Working Capital.** Our working capital improved from a surplus of \$16.6 million at December 31, 2005, to a surplus of \$94.8 million at September 30, 2006. The improvement primarily resulted from an increase in cash balances, and an increase in our accounts receivable balances, partially offset by an increase in accrued capital costs due to an increase in our drilling and facility construction activities from year-end 2005 levels.

**Capital Expenditures.** In the first nine months of 2006, we relied upon our net cash provided by operating activities of \$310.7 million and proceeds from the sale of property and equipment of \$20.3 million to fund capital expenditures of \$291.3 million. Our total capital expenditures of approximately \$291.3 million in the first nine months of 2006 included:

Domestic expenditures of \$244.0 million as follows:

- \$189.4 million for drilling and developmental activity costs, predominantly in our South Louisiana and AWP areas;
- \$43.6 million of domestic prospect costs, principally related to seismic activities, prospect leasehold, and geological costs of unproved prospects;
- \$11.0 million primarily for leasehold improvements in our Houston office, software, computer equipment, vehicles, furniture, and fixtures;

New Zealand expenditures of \$47.3 million as follows:

- \$39.1 million for drilling, developmental activity, and gas processing plant costs;
- \$7.8 million on prospect costs and geological costs of unproved properties;
- and \$0.4 million for computer equipment, software, furniture, and fixtures.

We successfully completed 35 of 49 wells in the first nine months of 2006, for a success rate of 71%. Domestically, we completed 32 of 42 wells for a success rate of 76%. A total of 17 wells were drilled in the Lake Washington area, of which 15 were completed, and 17 wells were drilled in the AWP Olmos area, of which 11 were completed. Six additional wells were drilled successfully, three in Cote Blanche Island and one each in Bay de Chene, South Bearhead Creek, and Brookeland. In Alaska, we drilled an unsuccessful exploratory well. In New Zealand, we drilled four development wells, three of which were completed, and drilled three unsuccessful exploratory wells.

Our current 2006 capital expenditure budget for our drilling and operations was increased to \$391 to \$415 million. We expect to spend an additional \$155 to \$161 million on the South Louisiana acquisition and the South Bearhead Creek acquisition of interests, net of approximately \$20 to \$25 million in dispositions. The \$20 to \$25 million of dispositions relate to non-core properties and is inclusive of the \$20 million sale of our minority interest in the Brookeland and Masters Creek natural gas processing plants. Approximately 85% of

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the 2006 budget is targeted for domestic activities, with about 15% planned for activities in New Zealand. We plan to spend \$250 to \$270 million in our South Louisiana region, which includes Lake Washington, Bay de Chene and Cote Blanche Island. We expect that our 2006 capital expenditures to approximate our cash flows provided from operating activities during 2006, as was the case in 2005. Our acquisitions are not budgeted and are being funded through cash on hand, cash flow and bank borrowings. For 2006, we have increased our production growth target to 70 to 71 Bcfe, from the previous range of 68 to 70.5 Bcfe and maintained our 5% to 8% targeted increase for proved reserves, over the 2005 levels.

For the last three months of 2006, we expect to make capital expenditures of approximately \$282 to \$314 million, which includes property acquisitions of \$174 to \$179 million. These estimated 2006 amounts include an increase due to higher drilling and services costs over prior year levels. Capital expenditures for 2005 totaled \$236 million.

Our 2006 capital expenditures continue to be focused on developing and producing long-lived reserves in South Louisiana, AWP Olmos, Rimu/Kauri, and TAWN areas, along with property acquisitions in the South Louisiana area. We expect our 2006 total production to increase over 2005 levels, primarily from our South Louisiana area. Our production in the AWP Olmos area is expected to remain relatively flat. We expect production in our other core areas to decrease as a limited amount of new drilling is currently budgeted to offset the natural production decline of these properties.

In New Zealand, we signed a natural gas supply agreement in July 2006 that covers production from our Rimu and Kauri wells until December 31, 2009. The benefits of the new agreement are to increase our sales price from the current price, termination of our existing sales agreements which called for lower sales prices on our natural gas production, and the ability to separately market production from new Rimu/Kauri wells with our purchaser retaining a right of first negotiation.

#### **New Accounting Pronouncements**

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

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

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109." This Interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, "Accounting for Income Taxes." FIN No. 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding derecognition, classification and disclosure of these uncertain tax positions. FIN No. 48 is effective for fiscal years beginning after December 15, 2006. The Company has not yet determined what, if any, impact this interpretation will have on its financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 addresses how companies should approach measuring fair value when required by GAAP; it does not create or modify

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any current GAAP requirements to apply fair value accounting. SFAS No. 157 provides a single definition for fair value that is to be applied consistently for all accounting applications, and also generally describes and prioritizes, according to reliability, the methods and inputs used in valuations. SFAS No. 157 prescribes various disclosures about financial statement categories and amounts which are measured at fair value, if such disclosures are not already specified elsewhere in GAAP. The new measurement and disclosure requirements of SFAS No. 157 are effective for us in the first quarter 2008. The Company has not yet determined what impact, if any, this Interpretation will have on its financial position or results of operations.

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**Forward Looking Statements**

The statements contained in this report that are not historical facts are forward-looking statements as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended. Such forward-looking statements may pertain to, among other things, financial results, capital expenditures, drilling activity, development activities, cost savings, production efforts and volumes, hydrocarbon reserves, hydrocarbon prices, liquidity, regulatory matters and competition. Such forward-looking statements generally are accompanied by words such as “plan,” “future,” “estimate,” “expect,” “budget,” “predict,” “anticipate,” “projected,” “should,” “believe” or other words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management’s current plans, expectations, estimates and assumptions, upon current market conditions, and upon engineering and geologic information available at this time, and is subject to change and to a number of risks and uncertainties, and therefore, actual results may differ materially. Among the factors that could cause actual results to differ materially are the uncertainty of finding, replacing, developing or acquiring reserves; fluctuations in crude oil, natural gas and natural gas liquids prices or demand; adequate availability of skilled personnel, services and supplies; the uncertainty of drilling results; potential failure or delays in achieving reserve or production levels from existing and future oil and gas development projects due to operating hazards, drilling risks and the inherent uncertainties in predicting oil and gas reserves and oil and gas reservoir performance; requirements for capital; general economic conditions; changes in geologic or engineering information; changes in market conditions; competition and government regulations; as well as the risks and uncertainties discussed herein, and set forth from time to time in our other public reports, filings and public statements. Also, because of the volatility in oil and gas prices and other factors, interim results are not necessarily indicative of those for a full year.

### Item 3.

## QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

### Commodity Risk

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

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

- Price Floors – At September 30, 2006, we had in place price floors in effect through the December 2006 contract month for oil, which are expected to cover approximately 45% to 50% of our domestic oil production for October 2006 through December 2006. The oil floors cover notional volumes of 900,000 barrels, and expire at various dates from October 2006 to December 2006, with a weighted average floor price of \$63.77 per barrel.
- New Zealand Gas Contracts – All of our current gas production in New Zealand is sold under long-term, fixed-price contracts denominated in New Zealand dollars. These contracts protect against price volatility, and our revenue from these contracts will vary only due to production fluctuations and foreign exchange rates.

### Customer Credit Risk

We are exposed to the risk of financial non-performance by customers. Our ability to collect on sales to our customers is dependent on the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers and seek to minimize exposure to any one customer where other customers are readily available. Due to availability of other purchasers, we do not believe that the loss of any single oil or gas customer would have a material adverse effect on our financial position or results of operations.

### Foreign Currency Risk

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

### Interest Rate Risk

Our Senior Notes due 2011 and Senior Subordinated Notes due 2012 have fixed interest rates; consequently we are not exposed to cash flow risk from market interest rate changes on these notes. However, there is a risk that market rates will decline and the required interest payments on our Senior Notes and Senior Subordinated Notes may exceed those payments based on the current market rate. At September 30, 2006, 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 83 basis points and would not have a material adverse effect on our 2006 cash flows based on this same level or a modest level of borrowing.

**Item 4.**

**CONTROLS AND PROCEDURES**

Disclosure Controls and Procedures

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

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the first nine months of 2006 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

**SWIFT ENERGY COMPANY**

**PART II. - OTHER INFORMATION**

**Item 1. Legal Proceedings.**

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

**Item 1A. Risk Factors.**

There have been no material changes in our risk factors from those disclosed in our 2005 Annual Report on Form 10-K.

**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.**

None.

**Item 5. Other Information.**

None.

**Item 6. Exhibits.**

10.1\* Third Amendment to First Amended and Restated Credit Agreement, effective as of October 2, 2006.

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.

\* Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

SWIFT ENERGY COMPANY  
(Registrant)

Date: November 3, 2006

By: \_\_\_\_\_ (original signed by)  
Alton D. Heckaman, Jr.  
Executive Vice President & Chief Financial Officer

Date: November 3, 2006

By: \_\_\_\_\_ (original signed by)  
David W. Wesson  
Controller & Principal Accounting 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 September 30, 2006, 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: November 3, 2006

/s/ Alton D. Heckaman Jr.  
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Alton D. Heckaman, Jr.  
Executive Vice President & Chief Financial Officer

**Certification of Chief Executive Officer and Chief Financial Officer**

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

In connection with the accompanying Quarterly Report on Form 10-Q for the period ended September 30, 2006 (the "Report") of Swift Energy Company ("Swift") as filed with the Securities and Exchange Commission on November 3, 2006, the undersigned, in his capacity as an officer of Swift, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

Dated: November 3, 2006

/s/ Alton D. Heckaman, Jr.

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

Dated: November 3, 2006

/s/ Terry E. Swift

Terry E. Swift  
Chairman of the Board &  
Chief Executive Officer