SWIFT ENERGY CO
Form 10-Q
May 05, 2011

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

FORM 10-Q

(X) Quarterly Report Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

For the quarterly period ended March 31, 2011
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 77060
(281) 874-2700
(Address and telephone number of principal executive offices)
Securities registered pursuant to Section 12(b) of the Act:

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 þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes þ No o

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	þ	Accelerated filer	o	Non-accelerated filer	o	Smaller reporting company	o

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

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

Common Stock ($.01 Par Value) (Class of Stock)	42,423,144 Shares (Outstanding at April 30, 2011)

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SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2011

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Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	March 31, 2011 (Unaudited)	December 31, 2010
ASSETS		
Current Assets:		
Cash and cash equivalents	$19,764	$86,367
Accounts receivable	65,443	46,975
Deferred tax asset	2,046	6,347
Other current assets	20,253	18,105
Current assets held for sale	564	564
Total Current Assets	108,070	158,358
Property and Equipment:		
Property and Equipment	4,084,463	3,951,107
Less – Accumulated depreciation, depletion, and amortization	(2,431,612)	(2,378,262)
Property and Equipment, Net	1,652,851	1,572,845
Other Long-Term Assets	12,340	12,713
Total Assets	$1,773,261	$1,743,916
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$70,849	$75,594
Accrued capital costs	68,967	64,879
Accrued interest	10,225	11,010
Undistributed oil and gas revenues	4,301	5,252
Total Current Liabilities	154,342	$156,735
Long-Term Debt	471,685	471,624
Deferred Income Taxes	164,037	157,565
Asset Retirement Obligation	70,529	70,171
Other Long-Term Liabilities	8,785	7,804
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, 42,889,488 and 42,440,583 shares issued, and 42,409,379 and 41,999,058 shares outstanding, respectively	429	424
Additional paid-in capital	713,072	706,857
Treasury stock held, at cost, 480,109 and 441,525 shares, respectively	(12,219)	(9,778)
Retained earnings	202,833	182,652
Accumulated other comprehensive loss, net of income tax	(232)	(138)
Total Stockholders' Equity	903,883	880,017

Total Liabilities and Stockholders' Equity	$1,773,261	$1,743,916

See accompanying Notes to Condensed Consolidated Financial Statements.

Condensed Consolidated Statements of Operations (Unaudited)
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	Three Months Ended	
	03/31/11	03/31/10
Revenues:		
Oil and gas sales	$144,201	$110,025
Price-risk management and other, net	(123)	(179)
Total Revenues	144,078	109,846
Costs and Expenses:		
General and administrative, net	10,443	9,251
Depreciation, depletion, and amortization	52,921	38,274
Accretion of asset retirement obligation	1,136	954
Lease operating cost	25,384	18,648
Severance and other taxes	13,313	11,572
Interest expense, net	8,388	8,326
Total Costs and Expenses	111,585	87,025
Income from Continuing Operations Before Income Taxes	32,493	22,821
Provision for Income Taxes	12,244	8,581
Income from Continuing Operations	20,249	14,240
Loss from Discontinued Operations, net of taxes	(68)	(35)
Net Income	$20,181	$14,205
Per Share Amounts-		
Basic: Income from Continuing Operations	$0.47	$0.37
Loss from Discontinued Operations, net of taxes	(0.00)	(0.00)
Net Income	$0.47	$0.37
Diluted: Income from Continuing Operations	$0.47	$0.37
Loss from Discontinued Operations, net of taxes	(0.00)	(0.00)
Net Income	$0.47	$0.37
Weighted Average Shares Outstanding - Basic	42,190	37,652

See accompanying Notes to Condensed Consolidated Financial statements.

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Condensed Consolidated Statements of Stockholders' Equity
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	Common Stock (1)	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2009	$379	$551,606	$(9,221)	$136,358	$ (223)	$678,899
Stock issued for benefit plans (59,335 shares)	-	242	1,271	-	-	1,513
Stock options exercised (136,432 shares)	1	2,086	-	-	-	2,087
Public Stock offering (4,038,270 shares)	40	140,099	-	-	-	140,139
Purchase of treasury shares (70,337 shares)	-	-	(1,828)	-	-	(1,828)
Tax benefits from stock compensation	-	28	-	-	-	28
Employee stock purchase plan (66,564 shares)	1	950	-	-	-	951
Issuance of restricted stock (312,191 shares)	3	(3)	-	-	-	-
Amortization of stock compensation	-	11,849	-	-	-	11,849
Net Income	-	-	-	46,294	-	46,294
Other comprehensive income	-	-	-	-	85	85
Total comprehensive income						46,379
Balance, December 31, 2010	$424	$706,857	$(9,778)	$182,652	$ (138)	$880,017
Stock issued for benefit plans (37,068 shares) (2)	-	791	821	-	-	1,612
Stock options exercised (99,262 shares) (2)	1	741	-	-	-	742
Purchase of treasury shares (75,652 shares)	-	-	(3,262)	-	-	(3,262)
Employee stock purchase plan (49,089 shares) (2)	1	999	-	-	-	1,000
Issuance of restricted stock (300,554 shares) (2)	3	(3)	-	-	-	-
Amortization of stock compensation (2)	-	3,687	-	-	-	3,687
Net Income (2)	-	-	-	20,181	-	20,181
Other comprehensive loss (2)	-	-	-	-	(94)	(94)
Total comprehensive income (2)						20,087
Balance, March 31, 2011 (2)	$429	$713,072	$(12,219)	$202,833	$ (232)	$903,883

(1) $.01 par value.
(2) Unaudited

See accompanying Notes to Condensed Consolidated Financial Statements.

Condensed Consolidated Statements of Cash Flows (Unaudited)
Swift Energy Company and Subsidiaries

(in thousands)	Three Months Ended March 31, 2011	2010
Cash Flows from Operating Activities:		
Net income	$20,181	$14,205
Plus loss from discontinued operations, net of taxes	68	35
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation, depletion, and amortization	52,921	38,274
Accretion of asset retirement obligation	1,136	954
Deferred income taxes	10,822	10,692
Stock-based compensation expense	2,684	2,364
Other	(8,589)	(2,557)
Change in assets and liabilities-		
Increase in accounts receivable	(13,612)	(713)
Decrease in accounts payable and accrued liabilities	(3,112)	(10,809)
Increase in income taxes payable	2	126
Increase (decrease) in accrued interest	(785)	6,694
Cash provided by operating activities – continuing operations	61,716	59,265
Cash provided by operating activities – discontinued operations	99	46
Net Cash Provided by Operating Activities	61,815	59,311
Cash Flows from Investing Activities:		
Additions to property and equipment	(131,911)	(63,386)
Proceeds from the sale of property and equipment	13	52
Cash used in investing activities – continuing operations	(131,898)	(63,334)
Cash provided by investing activities – discontinued operations	5,000	5,000
Net Cash Used in Investing Activities	(126,898)	(58,334)
Cash Flows from Financing Activities:		
Net proceeds from issuances of common stock	1,742	1,331
Purchase of treasury shares	(3,262)	(1,676)
Cash used in financing activities – continuing operations	(1,520)	(345)
Cash provided by financing activities – discontinued operations	---	---
Net Cash Used in Financing Activities	(1,520)	(345)
Net Increase (Decrease) in Cash and Cash Equivalents	(66,603)	632
Cash and Cash Equivalents at Beginning of Period	86,367	38,469
Cash and Cash Equivalents at End of Period	$19,764	$39,101
Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	$8,741	$1,340
Cash paid during period for income taxes	$1,420	$---

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 ("Swift Energy," the "Company," or "we") and reflect necessary adjustments, all of which were of a recurring nature unless otherwise disclosed herein, 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 our Annual Report on Form 10-K for the fiscal year ended December 31, 2010 as filed with the Securities and Exchange Commission.

(2) Summary of Significant Accounting Policies

Principles of Consolidation. The accompanying condensed consolidated financial statements include the accounts of Swift Energy and its wholly owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and gas properties, with a focus on inland waters and onshore oil and natural gas reserves in Louisiana and Texas. Our undivided interests in oil and gas properties 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 condensed consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying condensed consolidated financial statements.

Discontinued Operations. Unless otherwise indicated, information presented in the notes to the financial statements relates only to Swift Energy's continuing operations. Information related to discontinued operations is included in Note 6 and in some instances, where appropriate, is included as a separate disclosure within the individual footnotes.

Subsequent Events. We have evaluated subsequent events of our condensed consolidated financial statements. There were no material subsequent events requiring additional disclosure in these financial statements.

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 and assumptions 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,
- estimates related to the collectability of accounts receivable and the credit worthiness of our customers,
- estimates of the counterparty bank risk related to letters of credit that our customers may have issued on our behalf,
- estimates of future costs to develop and produce reserves,
- accruals related to oil and gas sales, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage, and the solvency of insurance providers,
- estimates in the calculation 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,

- estimates made in our income tax calculations, and
- estimates in the calculation of the fair value of hedging assets.

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 new accounting pronouncements, 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.

Property and Equipment. We follow the "full-cost" method of accounting for oil and natural 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 natural gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the three months ended March 31, 2011 and 2010, such internal costs capitalized totaled $7.2 million and $6.0 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the three months ended March 31, 2011 and 2010, capitalized interest on unproved properties totaled $1.9 million and $1.8 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

The "Property and Equipment" balances on the accompanying condensed consolidated balance sheets are summarized for presentation purposes. The following is a detailed breakout of our "Property and Equipment" balances.

(In Thousands)	March 31, 2011	December 31, 2010
Property and Equipment		
Proved oil and gas properties	$ 3,968,616	$ 3,835,173
Unproved oil and gas properties	78,248	78,429
Furniture, fixtures, and other equipment	37,599	37,505
Less – Accumulated depreciation, depletion, and amortization	(2,431,612)	(2,378,262)
Property and Equipment, Net	$ 1,652,851	$ 1,572,845

No gains or losses are recognized upon the sale or disposition of oil and natural gas properties, except in transactions involving a significant amount of reserves or where the proceeds from the sale of oil and natural gas properties would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a cost center. Internal costs associated with selling properties are expensed as incurred.

Future development costs are estimated property-by-property based on current economic conditions and are amortized to expense as our capitalized oil and gas property costs are amortized.

We compute the provision for depreciation, depletion, and amortization ("DD&A") of oil and natural gas properties using the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties—including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties—by an overall rate determined by dividing the physical units of oil and natural gas produced during the period by the total estimated units of proved oil and natural 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 are recorded at cost and are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between 2 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 property-by-property 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, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural 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 the preceding 12-months’ average price based on closing prices on the first day of each month, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects (“Ceiling Test”). Our hedges at March 31, 2011 consisted of oil and natural gas price floors that did not materially affect prices used in these calculations. This calculation is done on a country-by-country basis.

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

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could continue to change in the near term. If oil and natural gas prices decline from our prices used in the Ceiling Test, it is possible that non-cash write-downs of oil and natural gas properties could occur in the future. If we have significant declines in our oil and natural gas reserves volumes, which also reduce our estimate of discounted future net cash flows from proved oil and natural gas reserves, non-cash write-downs of our oil and natural gas properties could occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties if a decrease in oil and/or natural gas prices were to occur.

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 collectability of the revenue is probable. Swift Energy uses the entitlement method of accounting in which we recognize our 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 condensed consolidated balance sheets. Natural gas balancing receivables are reported in “Other current assets” on the accompanying condensed consolidated balance sheets when our ownership share of production exceeds sales. As of March 31, 2011, we did not have any material natural gas imbalances.

Reclassification of Prior Period Balances. Certain reclassifications have been made to prior period amounts to conform to the current-year presentation.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair value of the bank borrowings approximate the carrying amounts as of March 31, 2011 and December 31, 2010, and was determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of March 31, 2011 and December 31, 2010, the fair value of our senior notes due 2017, was $256.3 million, or 102.5% of face value, and $254.7 million, or 101.9% of face value, respectively. Based upon quoted market prices as of March 31, 2011 and December 31, 2010, the fair value of our senior notes due 2020, which were issued in November 2009, were $246.4 million, or 109.5% of face value and $242.3 million, or 107.7% of face value, respectively. The carrying value of our senior notes due 2017 was $250.0 million at March 31, 2011 and December 31, 2010, while the carrying value of our senior notes due 2020 was $221.7 million and $221.6 million at March 31, 2011 and December 31, 2010, respectively.

Accounts Receivable. We assess the collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At March 31, 2011 and December 31, 2010, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total “Accounts receivable” balance on the accompanying condensed consolidated balance sheets.

At March 31, 2011 our “Accounts Receivable” balance included $59.6 million for oil and gas sales, $4.9 million for joint interest owners and $0.9 million for other receivables. At December 31, 2010 our “Accounts receivable” balance included $43.3 million for oil and gas sales, $2.3 million for joint interest owners and $1.4 million for other receivables.

Debt Issuance Costs. Legal fees, accounting fees, underwriting fees, printing costs, and other direct expenses associated with extensions of our bank credit facility and public debt offerings were capitalized and are amortized on an effective interest basis over the life of each of the respective note offerings and credit facility.

The 7-1/8% senior notes due 2017 mature on June 1, 2017, and the balance of their issuance costs at March 31, 2011, was $2.9 million, net of accumulated amortization of $1.3 million. The 8-7/8% senior notes due 2020 mature on January 15, 2020, and the balance of their issuance costs at March 31, 2011, was $4.6 million, net of accumulated amortization of $0.4 million. The issuance costs associated with our revolving credit facility, which was extended in September 2010, had been capitalized and is being amortized over the life of the facility. The balance of revolving credit facility issuance costs at March 31, 2011, was $3.5 million, net of accumulated amortization of $3.4 million.

Insurance Claims. We have several open insurance claims filed in the ordinary course of business, none of which are material at the present time.

Price-Risk Management Activities. The Company follows FASB ASC 815-10, which requires that changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The guidance also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the condensed consolidated balance sheets 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 statement of operations 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 natural gas prices, mainly through the purchase of price floors and collars. During the first quarters of 2011 and 2010, we recognized net losses of $0.2 million and $0.5 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying condensed consolidated statements of operations. Had these losses been recognized in the oil and gas sales account they would not have materially changed our per unit sales prices received. At March 31, 2011, the Company had recorded $0.2 million, net of taxes of $0.1 million, of derivative losses in "Accumulated other comprehensive loss, net of income tax" on the accompanying condensed consolidated balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for the first three months of 2011 and 2010 was not material. All amounts currently held in "Accumulated other comprehensive loss, net of income tax" will be realized within the next three months when the forecasted sale of hedged production occurs.

At March 31, 2011, we had natural gas price floors in effect that covered a portion of our natural gas production for April to June 2011. These floors cover production of 3,915,000 MMBtu with strike prices ranging between $3.89 and $4.27 per MMBtu. We also had oil price floors in effect that covered a portion of our oil production for April to May 2011. These floors cover production of 388,000 barrels of oil with strike prices ranging between $94.25 and $100.70 per barrel.

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 loss, net of income tax." When the hedged transactions are recorded upon the actual sale of the oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive loss, net of income tax" on the accompanying condensed consolidated balance sheets and are recorded in “Price-risk management and other, net” on the accompanying condensed consolidated statements of operations. The fair values of our derivatives are computed using the Black-Scholes-Merton option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments at March 31, 2011 and December 31, 2010, was $0.7 million and $0.3 million, respectively and was recognized on the accompanying condensed consolidated balance sheets 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, to the extent they do not exceed actual costs incurred, are recorded as a reduction to “General and administrative, net.” Our supervision fees are based on COPAS guidelines. The amount of supervision fees charged in the first quarters of 2011 and 2010 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate was $3.5 million and $3.0 million in the first three months of 2011 and 2010, respectively.

Inventories. Inventories consist primarily of tubulars and other equipment that we expect to place in service in production operations. Inventories carried at cost (weighted average method) are included in "Other current assets" on the accompanying condensed consolidated balance sheets totaling $11.4 million at March 31, 2011 and $12.8 million at December 31, 2010.

Income Taxes. Under guidance contained in FASB ASC 740-10, 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.

We follow the recognition and disclosure provisions under guidance contained in FASB ASC 740-10-25. Under this guidance, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. Our current balance of unrecognized tax benefits is $1.0 million. If recognized, these tax benefits would fully impact our effective tax rate.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of March 31, 2011, we did not have any amount accrued for interest and penalties on uncertain tax positions.

Our U.S. Federal income tax returns for 2002 forward, our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2004, and our Texas franchise tax returns after 2006 remain subject to examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

Accounts Payable and Accrued Liabilities. The "Accounts Payable and Accrued Liabilities" balances on the accompanying condensed consolidated balance sheets are summarized below for presentation purposes. The following is a detailed breakout of certain items within "Accounts Payable and Accrued Liabilities" in the corresponding periods:

(In Thousands)	March 31, 2011	December 31, 2010
Trade accounts payable (1)	$ 21,797	$ 22,459
New Zealand deferred revenue	15,000	10,000
Accrued expenses	13,083	19,284
Asset retirement obligation – current portion	8,208	8,708
Accrued severance taxes	6,761	10,253
Other accrued liabilities	6,000	4,890
Total accounts payable and accrued liabilities	$ 70,849	$ 75,594

(1) Included in "trade accounts payable" are liabilities of approximately $10.4 million and $8.1 million at March 31, 2011 and December 31, 2010, respectively, for outstanding checks. This represents the amounts by which checks were issued, but not presented by vendors to the Company's banks for collection, exceeded balances in the applicable disbursement bank accounts.

Cash and Cash Equivalents. We consider all highly liquid instruments with an initial maturity of three months or less to be cash equivalents.

Restricted Cash. These balances primarily include amounts held in escrow accounts to satisfy domestic plugging and abandonment obligations. As of March 31, 2011 and December 31, 2010 these assets include approximately $1.3 million. These amounts are restricted as to their current use, and will be released when we have satisfied all plugging and abandonment obligations in certain fields. Restricted cash balances are reported in “Other long-term assets” on the accompanying condensed consolidated balance sheets.

Accumulated Other Comprehensive Loss, Net of Income Tax. We follow the guidance contained in FASB ASC 220-10, which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At March 31, 2011, we recorded $0.2 million, net of taxes of $0.1 million, of derivative losses in “Accumulated other comprehensive loss, net of income tax” on the accompanying condensed consolidated balance sheet. The components of accumulated other comprehensive loss and related tax effects for 2011 were as follows (in thousands):

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2010	$ (218)	$ 81	$ (137)
Change in fair value of cash flow hedges	19	(7)	12
Effect of cash flow hedges settled during the period	(167)	60	(107)
Other comprehensive loss at March 31, 2011	$ (366)	$ 134	$ (232)

Total comprehensive income was $20.1 million and $15.4 million for the first quarters of 2011 and 2010, respectively.

Asset Retirement Obligation. We record these obligations in accordance with the guidance contained in FASB ASC 410-20. This guidance 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 expected date of abandonment. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis over the estimated oil and natural gas reserves 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 balance. This guidance requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values.

The following provides a roll-forward of our asset retirement obligation:

(in thousands)	2011	2010
Asset Retirement Obligation recorded as of January 1	$ 78,879	$ 64,236
Accretion expense	1,136	954
Liabilities incurred for new wells and facilities construction	139	25
Reductions due to sold and abandoned wells	(32)	(75)
Revisions in estimated cash flows	(1,385)	---
Asset Retirement Obligation as of March 31	$ 78,737	$ 65,140

At March 31, 2011 and December 31, 2010, approximately $8.2 million and $8.7 million, respectively, of our asset retirement obligation are classified as a current liability in “Accounts payable and accrued liabilities” on the accompanying condensed consolidated balance sheets.

Public Stock Offering. In November 2010, we issued 4.0 million shares of our common stock in an underwritten public offering at a price of $36.60 per share. The gross proceeds from these sales were approximately $147.8 million, before deducting underwriting commissions and issuance costs totaling $7.7 million.

New Accounting Pronouncements. In 2009, we adopted ASU 2010-03 which amends oil and gas reserves accounting and disclosure guidance that aligns the oil and gas reserves estimation and disclosure requirements of Topic 932 (“Extractive Industries – Oil and Gas”) with the requirements of SEC Release No. 33-8995. These standards are discussed in detail in our annual report on Form 10-K for the year ended December 31, 2010. These new requirements did not have a material impact upon our reserves estimation or earnings during the initial post-adoption period of 2010.

(3) Stock-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 10K for the fiscal year ended December 31, 2010, for additional information related to these share-based compensation plans.

We follow guidance contained in FASB ASC 718 to account for share-based compensation.

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. 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. In accordance with guidance contained in FASB ASC 718, we are required to report excess tax benefits from the award of equity instruments as financing cash flows. For the three months ended March 31, 2011 and 2010, we did not recognize any excess tax benefit or shortfall.

Net cash proceeds from the exercise of stock options were $0.7 million and $0.4 million for the three months ended March 31, 2011 and 2010. The actual income tax benefit from stock option exercises was $0.9 million for the three months ended March 31, 2011 and $0.1 million for the three months ended March 31, 2010.

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees, which was recorded in "General and administrative, net" in the accompanying condensed consolidated statements of operations, was $2.5 million and $2.1 million for the quarters ended March 31, 2011 and 2010, respectively. Stock compensation recorded in lease operating cost was $0.1 million for the quarters ended March 31, 2011 and 2010. We also capitalized $1.0 million and $0.4 million of stock compensation in the first quarters of 2011 and 2010, respectively. We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the service period of the award.

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 options issued during the indicated periods:

	Three Months Ended March 31, 2011	2010
Dividend yield	0 %	0 %
Expected volatility	58.8 %	62.8 %
Risk-free interest rate	1.9 %	2.2 %
Expected life of options (in years)	3.9	4.4
Weighted-average grant-date fair value	$ 19.33	$ 12.65

The expected term for grants issued considers all relevant factors including historical and expected future employee exercise behavior. We have analyzed historical volatility, and based on an analysis of all relevant factors, we have used a 5.5 year look-back period to estimate expected volatility of our 2011 and 2010 stock option grants.

At March 31, 2011, we had $5.6 million of unrecognized compensation cost related to stock options, which is expected to be recognized over a weighted-average period of 1.4 years. The following table represents stock option activity for the three months ended March 31, 2011:

	Shares	Wtd. Avg. Exercise Price
Options outstanding, beginning of period	1,361,779	$ 29.67
Options granted	300,279	$ 42.67
Options canceled	(13,693)	$ 55.05
Options exercised	(171,341)	$ 22.37
Options outstanding, end of period	1,477,024	$ 32.93

Options exercisable, end of period	828,881	$	32.07

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at March 31, 2011 and 2010 was $15.8 million and 6.1 years and $10.0 million and 4.5 years, respectively. The total intrinsic value of options exercised during the three months ended March 31, 2011 was $3.4 million.

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, 2010, 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 three years).

The compensation expense for these awards was determined based on the closing 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 March 31, 2011, we had unrecognized compensation expense of $22.4 million related to restricted stock awards which is expected to be recognized over a weighted-average period of 1.5 years. The grant date fair value of shares vested during the three months ended March 31, 2011 was $7.3 million.

The following table represents restricted stock activity for the three months ended March 31, 2011:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	734,286	$ 22.87
Restricted shares granted	388,250	$ 42.61
Restricted shares canceled	(5,012)	$ 26.21
Restricted shares vested	(300,554)	$ 24.31
Restricted shares outstanding, end of period	816,970	$ 31.70

(4) Earnings Per Share

The Company computes earnings per share in accordance with FASB ASC 260-10. Under the guidance, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are participating securities and, therefore, are included in computing basic earnings per share (EPS) pursuant to the two-class method. The two-class method determines earnings per share for each class of common stock and participating securities according to dividends or dividend equivalents and their respective participation rights in undistributed earnings.

Basic earnings per share (“Basic EPS”) has been computed using the weighted average number of common shares outstanding during each period. Diluted EPS for the quarters ended March 31, 2011 and 2010 assumes, as of the beginning of the period, exercise of stock options using the treasury stock method. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the three month periods ended March 31, 2011 and 2010, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the three month periods ended March 31, 2011 and 2010 (in thousands, except per share amounts):

	Three Months Ended March 31, 2011			Three Months Ended March 31, 2010		
	Income from Continuing Operations	Shares	Per Share Amount	Income from Continuing Operations	Shares	Per Share Amount
Basic EPS:						
Income from continuing operations, and Share Amounts	$20,249	42,190		$14,240	37,652	
Less: Income from continuing operations allocated to unvested shareholders	(370)	---		(269)	---	
Income from continuing operations allocated to common shares	$19,879	42,190	$0.47	$13,971	37,652	$0.37
Dilutive Securities:						
Plus: Income from continuing operations allocated to unvested shareholders	370	---		269	---	
Less: Income from continuing operations re-allocated to unvested shareholders	(368)	---		(268)	---	
Stock Options	---	319		---	218	
Diluted EPS:						
Income from continuing operations allocated to common shares, and assumed share conversions	$19,881	42,509	$0.47	$13,972	37,870	$0.37

Options to purchase approximately 1.5 million shares at an average exercise price of $32.93 were outstanding at March 31, 2011, while options to purchase approximately 1.5 million shares at an average exercise price of $29.06 were outstanding at March 31, 2010. Approximately 0.6 million and 0.8 million stock options to purchase shares were not included in the computation of Diluted EPS for both the three months ended March 31, 2011 and 2010, because these stock options were antidilutive, in that the sum of the stock option price, unrecognized compensation expense and excess tax benefits recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during those periods.

(5) Long-Term Debt

Our long-term debt as of March 31, 2011 and December 31, 2010, was as follows (in thousands):

	March 31, 2011	December 31, 2010
Bank Borrowings	$ ---	$ ---
7-1/8% senior notes due 2017	250,000	250,000
8-7/8% senior notes due 2020	221,685	221,624

Long-Term Debt	$ 471,685	$ 471,624

The maturities on our long-term debt are $250.0 million in 2017 and $225.0 million in 2020.

We have capitalized interest on our unproved properties in the amount of $1.9 million and $1.8 million for the three months ended March 31, 2011 and 2010, respectively.

Bank Borrowings. In September 2010 we renewed and extended our $500.0 million credit facility with a syndicate of nine banks through October 15, 2015, and have included a feature that allows the Company to increase the aggregate facility amount available up to $700.0 million with additional commitments from the lenders. We also increased our borrowing base to $300.0 million from $277.5 million. Debt issuance costs of approximately $3.6 million related to the extension of the credit facility were capitalized and are being amortized over the life of the facility.

At March 31, 2011 and 2010 we had no borrowings under our $500.0 million credit facility. The interest rate on our credit facility is either (a) the lead bank's prime plus an applicable margin or (b) LIBOR plus an applicable margin. However with respect to (a), if the lead bank's prime rate is not higher than each of the federal funds rate plus ½%, and the adjusted London Interbank Offered Rate ("LIBOR") plus 1%, the greatest of these three rates will then apply. The applicable margins vary depending on the level of outstanding debt with escalating rates of 100 to 200 basis points above the Alternative Base Rate and escalating rates of 200 to 300 basis points for LIBOR loans. The commitment fee associated with the unfunded portion of the borrowing base is set at 50 basis points. At March 31, 2011, the lead bank's prime rate was 3.25%.

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), a remaining aggregate limitation on purchases of our stock of $50.0 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. 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 natural gas properties. Under the terms of the credit facility, we can increase the commitment amount to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. In conjunction with our regularly scheduled borrowing base redetermination, which occurs every six months and is currently underway, we expect the borrowing base amount to remain at or above the current level.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $0.6 million and $0.4 million for the three months ended March 31, 2011 and 2010, respectively. The amount of commitment fees included in interest expense, net was $0.4 million and $0.3 million for each of the three month periods ended March 31, 2011 and 2010, respectively.

Senior Notes Due 2020. These notes consist of $225 million of 8-7/8% senior notes issued at 98.389% of par, which equates to an effective yield to maturity of 9-1/8%. The notes were issued on November 25, 2009 with an original discount of $3.6 million and will mature on January 15, 2020. The original discount of $3.6 million is recorded in "Long-Term Debt" on our condensed consolidated balance sheets and will be amortized over the life of the notes. 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 will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on January 15 and July 15 and commenced on November 25, 2009. On or after January 15, 2015, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.438% of principal, declining in twelve-month intervals to 100% in 2018 and thereafter. In addition, prior to January 15, 2013, we may redeem up to 35% of the principal amount of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 108.875% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $5.0 million of debt issuance costs related to these notes, which is included in "Other Long–Term Assets" on the accompanying condensed consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of 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 8-7/8% senior notes due 2020, including amortization of debt issuance costs and debt discount, totaled $5.1 million for each of the three months ended March 31, 2011 and 2010, respectively.

Senior Notes Due 2017. These notes consist of $250.0 million of 7-1/8% senior notes due 2017, which were issued on June 1, 2007 at 100% of the principal amount and will mature on June 1, 2017. 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 will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on June 1 and December 1, and commenced on December 1, 2007. On or after June 1, 2012, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.563% of principal, declining in twelve-month intervals to 100% in 2015 and thereafter. We incurred approximately $4.2 million of debt issuance costs related to these notes, which is included in “Other Long-Term Assets” on the accompanying condensed consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of 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 7-1/8% senior notes due 2017, including amortization of debt issuance costs, totaled $4.5 million for each of the three month periods ended March 31, 2011 and 2010, respectively.

(6) Discontinued Operations

In August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments to be received nine months after the sale, 18 months after the sale, and 30 months after the sale. In accordance with guidance contained in FASB ASC 360-10, the results of operations for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. As of March 31, 2011 all payments under this sale agreement had been received. Due to ongoing litigation, we have evaluated the situation and determined that certain revenue recognition criteria have not been met at this time for the permit sale, and have deferred the potential gain on this property sale pending further development of this litigation.

The book value of our remaining New Zealand permit was approximately $0.6 million at both March 31, 2011 and December 31, 2010 and is classified as held for sale in the condensed consolidated balance sheets. Our loss from discontinued operations, net of taxes was less than $0.1 million in both the first quarters of 2011 and 2010, which equated to $0.00 per basic and diluted share in both periods. Our cash provided by operating activities – discontinued operations was less than $0.1 million in both the first quarters of 2011 and 2010.

(7) Acquisitions and Dispositions

There were no material acquisitions or dispositions in 2010 or the first quarter of 2011.

(8) Fair Value Measurements

FASB ASC 820-10 defines fair value, establishes guidelines for measuring fair value and expands disclosure about fair value measurements. It does not create or modify any current GAAP requirements to apply fair value accounting. However, it provides a single definition for fair value that is to be applied consistently for all prior accounting pronouncements. The adoption of this guidance did not have a material impact on our financial position or results of operations.

The following table presents our assets that are measured at fair value as of March 31, 2011 and are categorized using the fair value hierarchy. The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (in millions):

	Fair Value Measurements at March 31, 2011			
Assets	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Money Market Funds	$ 15.1	$ 15.1	$ ---	$ ---
Natural Gas Derivatives	$ 0.2	$ ---	$ 0.2	$ ---
Oil Derivatives	$ 0.5	$ ---	$ 0.5	$ ---

Level 1 – Uses quoted prices in active markets for identical, unrestricted assets or liabilities. Instruments in this category include money market funds as they have comparable fair values for identical assets.

Level 2 – Uses quoted prices for similar assets or liabilities in active markets or observable inputs for assets or liabilities in non-active markets. Instruments in this category include our commodity derivatives that we value using commonly accepted industry-standard models (such as Black-Scholes) which contain inputs such as contract prices, risk-free rates, volatility measurements and other observable market data that are obtained from independent third-party sources.

Level 3 – Uses unobservable inputs for assets or liabilities that are in non-active markets. We do not have any assets or liabilities in this category that are not supported by market activity and have significant unobservable inputs.

(9) Condensed Consolidating Financial Information

Swift Energy Company is the issuer and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) is a guarantor of our senior notes due 2017 and 2020. The guarantees on our senior notes due 2017 and 2020 are full and unconditional. The following is condensed consolidating financial information for Swift Energy Company, Swift Energy Operating, LLC, and other subsidiaries:

Condensed Consolidating Balance Sheets

(in thousands)	March 31, 2011				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
ASSETS					
Current assets	$---	$107,948	$122	$---	$ 108,070
Property and equipment	---	1,652,851	---	---	1,652,851
Investment in subsidiaries (equity method)	903,883	---	832,714	(1,736,597)	---
Other assets	---	12,340	86,077	(86,077)	12,340
Total assets	$903,883	$1,773,139	$918,913	$(1,822,674)	$ 1,773,261
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$---	$139,312	$15,030	$---	$ 154,342
Long-term liabilities	---	801,113	---	(86,077)	715,036
Stockholders' equity	903,883	832,714	903,883	(1,736,597)	903,883
Total liabilities and stockholders' equity	$903,883	$1,773,139	$918,913	$(1,822,674)	$ 1,773,261

(in thousands)	December 31, 2010				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
ASSETS					
Current assets	$---	$158,335	$23	$---	$ 158,358
Property and equipment	---	1,572,845	---	---	1,572,845
Investment in subsidiaries (equity method)	880,017	---	808,780	(1,688,797)	---
Other assets	---	12,713	81,221	(81,221)	12,713
Total assets	$880,017	$1,743,893	$890,024	$(1,770,018)	$ 1,743,916
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$---	$146,728	$10,007	$---	$ 156,735

Long-term liabilities	---	788,385	---	(81,221)	707,164
Stockholders’ equity	880,017	808,780	880,017	(1,688,797)	880,017
Total liabilities and stockholders’ equity	$ 880,017	$ 1,743,893	$ 890,024	$ (1,770,018)	$ 1,743,916

Condensed Consolidating Statements of Income

(in thousands)	Three Months Ended March 31, 2011				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Revenues	$---	$144,078	$---	$ ---	$ 144,078
Expenses	---	111,585	---	---	111,585
Income before the following:	---	32,493	---	---	32,493
Equity in net earnings of subsidiaries	20,181	---	20,249	(40,430)	---
Income from continuing operations, before income taxes	20,181	32,493	20,249	(40,430)	32,493
Income tax provision	---	12,244	---	---	12,244
Income from continuing operations	20,181	20,249	20,249	(40,430)	20,249
Loss from discontinued operations, net of taxes	---	---	(68)	---	(68)
Net income	$20,181	$20,249	$20,181	$ (40,430)	$ 20,181

(in thousands)	Three months Ended March 31, 2010				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Revenues	$---	$109,846	$---	$ ---	$ 109,846
Expenses	---	87,025	---	---	87,025
Income before the following:	---	22,821	---	---	22,821
Equity in net earnings of subsidiaries	14,205	---	14,240	(28,445)	---
Income from continuing operations, before income taxes	14,205	22,821	14,240	(28,445)	22,821
Income tax provision	---	8,581	---	---	8,581
Income from continuing operations	14,205	14,240	14,240	(28,445)	14,240
Loss from discontinued operations, net of taxes	---	---	(35)	---	(35)
Net income	$14,205	$14,240	$14,205	$ (28,445)	$ 14,205

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Condensed Consolidating Statements of Cash Flow

(in thousands)	Three Months Ended March 31, 2011				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Cash flow from operations	$---	$61,716	$99	$ ---	$ 61,815
Cash flow from investing activities	---	(126,898)	5,000	(5,000)	(126,898)
Cash flow from financing activities	---	(1,520)	(5,000)	5,000	(1,520)
Net increase (decrease) in cash	---	(66,702)	99	---	(66,603)
Cash, beginning of period	---	86,346	21	---	86,367
Cash, end of period	$---	$19,644	$120	$ ---	$ 19,764

(in thousands)	Three Months Ended March 31, 2010				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Cash flow from operations	$---	$59,265	$46	$ ---	$ 59,311
Cash flow from investing activities	---	(58,334)	5,000	(5,000)	(58,334)
Cash flow from financing activities	---	(345)	(5,000)	5,000	(345)
Net increase in cash	---	586	46	---	632
Cash, beginning of period	---	33,406	5,063	---	38,469
Cash, end of period	$---	$33,992	$5,109	$ ---	$ 39,101

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

You should read the following discussion and analysis in conjunction with our financial information and our consolidated financial statements and accompanying notes included in this report and our annual reports on Form 10-K for the years ended December 31, 2010, 2009, and 2008. Unless otherwise noted, both historical information for all periods and forward-looking information provided in this Management's Discussion and Analysis relates solely to our continuing operations located in the United States, and excludes our New Zealand discontinued operations. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 29 of this report.

Overview

We are an independent oil and natural gas company formed in 1979, and we are engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from our Texas properties as well as onshore and inland waters of Louisiana. We are one of the largest producers of crude oil in the state of Louisiana, and hold a large acreage position in Texas prospective for liquids-rich Eagle Ford shale and Olmos tight sands development. Oil production accounted for 37% of our first quarter of 2011 production and 67% of our oil and gas revenues, and combined production for both oil and natural gas liquids ("NGLs") made up 50% of our first quarter of 2011 production and 79% of our oil and gas sales. This emphasis has allowed us to benefit from better margins for oil production than natural gas production during the quarter.

First Quarter 2011 Highlights

Increases in Earnings and Production. Our income increased by $6.0 million and our production volumes increased by 29% in the first quarter of 2011 when compared to the same period in 2010. Natural gas and NGL production volumes increased 65% and 15% in the first quarter of 2011, respectively, due to our recent South Texas activities, while oil volumes increased 4% from the first quarter of 2010. Prices received for oil and NGLs in the first quarter of 2011 were 26% and 9% higher, respectively, than average prices we received in the first quarter of 2010, while natural gas prices declined 19%.

Liquidity at Quarter-End. In November 2010, we raised $140.1 million net through an underwritten public stock offering of 4.0 million shares of our common stock at a price of $36.60 per share and we ended the first quarter of 2011 with $19.8 million of cash and cash equivalents on our balance sheet. Taken together with $300.0 million of borrowing capacity under our credit agreement at March 31, 2010, our liquidity provides capital, if needed, for our expanded 2011 drilling program.

First Quarter 2011 Drilling and Operational Activities. In our South Texas core region, two operated and one non-operated, horizontal, development wells were drilled to the Eagle Ford shale. Three operated horizontal development wells were drilled in the Olmos formation. All drilling activity in this area in the first quarter was in McMullen County, Texas. As of March 31, 2011, a total of four horizontal wells were awaiting completion activities, with one completed in April. At the end of 2010, our South Texas core region surpassed Southeast Louisiana in terms of both production and proven reserves. We had also entered into a long-term agreement with a major industry service provider for South Texas, securing access to hydraulic fracturing services at competitive prices for a two-year period with over one year still remaining on the contract.

In our Southeast Louisiana core region, we drilled an extension well in the Lake Washington field with two to four additional wells planned for the remainder of 2011. Recompletion and production optimization work continued during the quarter at the Lake Washington field. The average initial production response of five recompletions that were performed was approximately 480 gross Boe per day. The fourteen production optimization projects that were carried out averaged an initial production response of approximately 224 gross Boe/d. With no new wells being brought online during the quarter, these low cost operations led to a 4% sequential increase in net daily production at Lake Washington during the quarter. This focused effort on relatively low risk, low cost oil activity will continue throughout 2011.

In our Central Louisiana/East Texas core region, we drilled and completed one non-operated horizontal well in our Brookeland field.

Development Joint Ventures. Over the last 18 months we have entered into joint venture agreements with large independent oil and gas producers covering acreage in both our AWP and Burr Ferry fields, allowing us to both monetize a portion of our significant acreage positions (including a 26,000 acre portion of our Eagle Ford Shale acreage in McMullen County, Texas) and share costs of development drilling in these fields in order to accelerate their development.

Potential Dispositions. We recently engaged a firm to facilitate the sale of certain non-strategic properties located in Louisiana and Texas. The fields in Louisiana include Horseshoe Bayou/Bayou Sale, High Island, Bayou Penchant, Jeanerette, Cote Blanche Island and Chunchula. Aggregate daily production of these fields is approximately 1,557 Boe/d. The Texas fields include Bego South and Briscoe Ranch. The total daily production of these two fields in Texas is approximately 372 Boe/d.

2011 Objectives

In 2011, we are focused on accelerating our pace of development in South Texas, improving our results through more efficient execution and exploiting other areas of our asset base. Our exposure to liquids rich production growth in South Texas, our oil production in South Louisiana, our growing leasehold acreage in the Austin Chalk and our deep exploration prospect inventory along the Gulf Coast together provide a uniquely positioned resource portfolio. For 2011, we are targeting an increase in production volumes of 30% to 33% over 2010 levels and reserves growth of 15% to 20% over 2010 levels.

Results of Operations

Summary Prior Quarter Comparison

In the first quarter of 2011 we had revenues of $144.1 million, an increase of 24% compared to fourth quarter 2010 levels. Production volumes increased 21%, and our weighted average sales price received increased 3% to $54.51 per Boe from $52.98 per Boe. This $28.0 million increase in revenues from fourth quarter 2010 levels was mainly due to a 15% increase in oil prices along with a 44% increase in natural gas production volumes during the first quarter of 2011. The increase in natural gas production was from our South Texas fields.

Our overall costs and expenses increased in the first quarter of 2011 by $12.9 million when compared to fourth quarter 2010 levels, but were lower on a Boe basis, as production volumes increased 21%. Depreciation, depletion and amortization expense increased 19%, mainly due to higher production volumes and a higher depletable property base, partially offset by higher reserves volumes in the 2011 period. Lease operating costs increased by 13% due to increased transportation and other costs in our South Texas core region. Severance and other taxes also increased 13% mainly due to increased oil and gas revenues.

Net income for the first quarter of 2011 was $20.2 million compared to $10.3 million in the fourth quarter of 2010.

Revenues

Our properties are divided into the following core regions, each of which includes the fields listed:

- South Texas

- Olmos

AWP
Sun TSH
Las Tiendas

- Eagle Ford

Hawkville AWP
Hawkville Artesia Wells
Hawkville Fasken

- Southeast Louisiana

Lake Washington
Bay de Chene

- Central and South Louisiana / East Texas

Brookeland
South Bearhead Creek
Masters Creek
Burr Ferry
Horseshoe Bayou/Bayou Sale
Jeanerette
Cote Blanche Island

The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the three months ended March 31, 2011 and 2010:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2011	2010	2011	2010
S. E. Louisiana	$71.0	$61.4	870	936
South Texas	49.6	31.5	1,361	790
Central and South Louisiana / E. Texas	23.0	16.3	402	303
Other	0.6	0.8	13	16
Total	$144.2	$110.0	2,646	2,045

2011 First Quarter Revenues Breakdown. Oil and gas sales for the first quarter of 2011 increased by 31%, or $34.2 million, from the level of those revenues for the comparable 2010 period, and our net production volumes in the first quarter of 2011 increased by 29%, or 0.6 MMBoe, from net production volumes in the first quarter of 2010. Average prices for oil increased to $98.61 per Bbl in the first quarter of 2011 from $78.10 per Bbl in the first quarter of 2010. Average natural gas prices decreased to $3.82 per Mcf in the first quarter of 2011 from $4.74 per Mcf in the first quarter of 2010. Average NGL prices increased to $48.87 per Bbl in the first quarter of 2011 from $44.71 per Bbl in the first quarter of 2010.

In the first quarter of 2011, our $34.2 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $14.4 million favorable impact on sales, of which $20.2 million was attributable to the 26% increase in average oil prices received, $1.5 million was attributable to the 9% increase in NGL prices, and a reduction of ($7.3) million was attributable to the 19% decrease in natural gas prices; and
- Volume increases that had a $19.8 million favorable impact on sales, with a $3.1 million increase attributable to the less than 0.1 million Bbl increase in oil production volumes, a $2.0 million increase due to the less than 0.1 million Bbl increase in NGL production volumes, and a $14.7 million increase due to the 3.1 Bcf increase in natural gas production volumes.

The following table provides additional information regarding our quarterly oil and gas sales excluding any effects of our hedging activities:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)

Three Months Ended March 31, 2011	985	348	7.9	2,646	$98.61	$48.87	$3.82
Three Months Ended March 31, 2010	945	303	4.8	2,045	$78.10	$44.71	$4.74

During the first quarter of 2011, we recorded a net loss of $0.2 million related to our derivative activities, while during the first quarter of 2010 we recorded a net loss of $0.5 million from these activities. This activity is recorded in "Price-risk management and other, net" on the accompanying condensed statements of operations. Had these losses been recognized in the oil and gas sales account, our average oil price would have been $98.31 and $78.09 for the first quarters of 2011 and 2010, respectively, and our average natural gas price would have been $3.83 and $4.64 for the first quarters of 2011 and 2010, respectively.

Costs and Expenses.

Our expenses in the first quarter of 2011 increased $24.6 million, or 28%, compared to the first quarter of 2010 for the reasons noted below.

Lease Operating Expenses ("LOE"). These expenses increased $6.7 million, or 36%, compared to the level of such expenses in the first quarter of 2010. Lease operating costs increased during 2011 due to higher product transportation costs as well as other various cost increases from our South Texas core region. Our lease operating costs per Boe produced were $9.59 and $9.12 the first quarters of 2011 and 2010, respectively.

Depreciation, Depletion and Amortization ("DD&A"). These expenses increased $14.6 million, or 38% from the first quarter of 2010. The increase was due to a higher depletable base and higher production volumes, partially offset by higher reserves volumes. Our DD&A rate per Boe of production was $20.00 and $18.72 in the first quarters of 2011 and 2010, respectively, resulting from increases in per unit cost of reserves additions in 2011 and 2010.

General and Administrative Expenses, Net. These expenses increased $1.2 million, or 13%, from the level of such expenses in the first quarter of 2010. The increase was primarily due to higher stock and deferred compensation amounts in the first quarter of 2011, partially offset by higher capitalized amounts. For the first quarters of 2011 and 2010, our capitalized general and administrative costs totaled $7.2 million and $6.0 million, respectively. Our net general and administrative expenses per Boe produced decreased to $3.95 per Boe in the first quarter of 2011 from $4.52 per Boe in the first quarter of 2010. The portion of supervision fees recorded as a reduction to general and administrative expenses were $3.5 million and $3.0 million for the first quarters of 2011 and 2010, respectively

Severance and other taxes. These expenses increased $1.7 million, or 15%, from the first quarter of 2010. The increases were due primarily to higher revenues from higher natural gas production and higher oil prices. Severance and other taxes, as a percentage of oil and gas sales, were approximately 9.2% and 10.5% in the first quarters of 2011 and 2010, respectively. The decrease in 2011 was primarily driven by a shift in product and regional mix as well as reduced tax rates for tight sand gas production related to South Texas Olmos and Eagle Ford completions.

Interest. Our gross interest cost in the first quarter of 2011 was $10.3 million, of which $1.9 million was capitalized. Our gross interest cost in the first quarter of 2010 was $10.1 million, of which $1.8 million was capitalized.

Income Taxes. Our effective income tax rate was 37.7% and 37.6% for the first quarters of 2011 and 2010, respectively. Our U.S. Federal income tax returns for 2002 forward, our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2004, and our Texas franchise tax returns after 2006 remain subject to examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

The primary upward adjustments in the effective tax rate above the U.S. statutory rate are the provision for state income taxes (computed net of the offsetting federal benefit) and non-deductible equity compensation.

Net Income. Our first quarter 2011 net income of $20.2 million increased, as compared to our first quarter 2010 net income of $14.2 million.

Known Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and this volatility is expected to continue in future periods. Factors such as worldwide economic conditions and credit availability, worldwide supply disruptions, weather conditions, fluctuating currency exchange rates, and political conditions in major oil producing regions, especially the

Middle East, can cause fluctuations in the price of oil. Domestic natural gas prices have shown slight improvement through 2010 into early 2011; however they remain significantly below prices in 2008. North American weather conditions, the industrial and consumer demand for natural gas, economic conditions and credit availability, storage levels of natural gas, the level of liquefied natural gas imports, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas.

Hurricane activity in the Gulf of Mexico may have a direct impact on our costs and operations. Extreme weather conditions in our Southeast Louisiana areas of activity can increase our costs, adversely affect our operations, and cause equipment or well damage, which damage may not be fully insured, and is not covered by business interruption insurance.

Due to the cyclical nature of the oil and gas industry and during periods of increased levels of exploration and production in particular areas, such as we are currently experiencing in the Olmos and Eagle Ford formations, there is increased demand for drilling rigs, equipment, supplies, oilfield services, and trained and experienced personnel. The high demand in these areas has caused shortages and delays, which has raised costs and often delayed field development.

The oil and gas industry is subject to the indirect consequences of regulations that could expose us to risks of increasing environmental laws and regulations (and possibly increased costs of operations), delays in obtaining permits and licenses, and reduced demand for crude oil and natural gas, among others.

Liquidity and Capital Resources

Capital Expenditures

2011 Capital Expenditures Incurred. Our capital expenditures were $131.9 million in the first quarter of 2011 compared to $63.4 million spent in the first quarter of 2010. The increase of $68.5 million was mainly due to additional drilling and completion activity in our South Texas core region. These 2011 expenditures were primarily funded by $61.7 million of cash provided by operating activities and $66.6 million in cash proceeds remaining from our stock offering in November 2010.

2011 Capital Expenditures Planned. We currently plan to finance our 2011 accrual based capital expenditures with our 2011 cash flow, cash on hand and potential line of credit borrowings. Our 2011 capital expenditures are currently budgeted at $430 million to $480 million, net of potential dispositions of non-strategic properties estimated at $30 million to $40 million. Approximately 80% of our capital budget is targeted for our South Texas core region. The Company may also explore both joint venture arrangements for particular prospects and select property dispositions, in each case to accelerate drilling and development of its assets and diversify its risk profile. For 2011, we are targeting an increase in production volumes of 30% to 33% over 2010 levels and reserves growth of 15% to 20% over 2010 levels.

Sources of Funds

Net Cash Provided by Operating Activities. For the first three months of 2011, our net cash provided by operating activities was $61.7 million, representing a 4% increase as compared to $59.3 million generated during the first quarter of 2010. The $2.5 million change was primarily due to a significant increase in natural gas production as well as higher oil prices, offset by lower natural gas prices during the first quarter of 2011.

Existing Credit Facility. In September 2010 we renewed and extended our $500.0 million credit facility through October 2015, increasing our borrowing base to $300.0 million from $277.5 million. We had no amounts drawn under our credit facility as of March 31, 2011. In conjunction with our regularly scheduled borrowing base redetermination, which occurs every six months and is currently underway, we expect the borrowing base amount to remain at or above the current level. Our revolving credit facility includes 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 and expect to remain in compliance with these provisions in future periods. Our available borrowings under our line of credit facility provide us liquidity. In light of credit market volatility in recent years which caused many financial institutions to experience liquidity issues, we periodically review the creditworthiness of the banks that fund our credit facility.

2010 Public Stock Offering. We raised $140.1 million net through an underwritten public stock offering in November 2010, issuing 4.0 million shares of our common stock at a price of $36.60 per share. The gross proceeds from these sales were approximately $147.8 million, before deducting underwriting commissions and issuance costs totaling $7.7 million. We used the proceeds from this stock sale to expand our South Texas drilling program and pay down a portion of the outstanding balance on our credit facility which increased liquidity.

Financial Ratios

Working Capital and Debt to Capitalization Ratio. Our working capital decreased from a surplus of $1.6 million at December 31, 2010, to a deficit of $46.3 million at March 31, 2011. The change primarily resulted from a decrease in cash and cash equivalents as we used cash received from our equity offering in 2010 to fund ongoing operations including our 2011 capital program. Working capital, which is calculated as current assets less current liabilities, can be used to measure both a company's operational efficiency and short-term financial health. The Company uses this measure to track our short-term financial position. Our debt to capitalization ratio decreased to 34% at March 31, 2011, as compared to 35% at December 31, 2010, primarily due to the increase in retained earnings from our first quarter 2011 net income.

Contractual Commitments and Obligations

We had no material changes in our contractual commitments and obligations from December 31, 2010 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, 2010.

Critical Accounting Policies and New Accounting Pronouncements

Property and Equipment. We follow the “full-cost” method of accounting for oil and natural 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 natural gas reserves are capitalized including internal costs incurred that are directly related to these activities and which are not related to production, general corporate overhead, or similar activities. Future development costs are estimated property-by-property based on current economic conditions and are amortized to expense as our capitalized oil and natural gas property costs are amortized.

We compute the provision for depreciation, depletion, and amortization (“DD&A”) of oil and natural gas properties using the unit-of-production method. This calculation is done on a country-by-country basis.

The costs of unproved properties not being amortized are assessed quarterly, on a property-by-property 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, and available geological and geophysical information. As these factors may change from period to period, our evaluation of these factors will change. Any impairment assessed is added to the cost of proved properties being amortized.

The calculation of the provision for DD&A requires us to use estimates related to quantities of proved oil and natural gas reserves and estimates of unproved properties. For both reserves estimates (see discussion below) and the impairment of unproved properties (see discussion above), these processes are subjective, and results may change over time based on current information and industry conditions. 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.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural 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”). We did not have any outstanding derivative instruments at March 31, 2011 that materially affect this calculation.

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. See the discussion above related to reserves estimation.

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could continue to change in the near-term. If oil and natural 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. If we have significant declines in our oil and natural gas reserves volumes, which also reduce our estimate of discounted future net cash flows from proved oil and natural gas reserves, non-cash write-downs of our oil and natural gas properties could occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties if a decrease in oil and/or natural gas prices were to occur.

New Accounting Pronouncements. There are no material new accounting pronouncements that have been issued but not yet adopted as of March 31, 2011.

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 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, cash flows, available borrowing capacity, liquidity, acquisition plans, regulatory matters, and competition. Such forward-looking statements generally are accompanied by words such as "plan," "future," "estimate," "expect," "budget," "predict," "anticipate," "projected," "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 from those projected. Among the factors that could cause actual results to differ materially are: volatility in oil and natural gas prices; availability of services and supplies; disruption of operations and damage due to hurricanes or tropical storms; fluctuations of the prices received or demand for our oil and natural gas; the uncertainty of drilling results and reserve estimates; operating hazards; requirements for and availability of capital; conditions in the financial and credit markets; 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 in this report and set forth from time to time in our other public reports, filings, and public statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. Significant declines in oil and natural gas prices began in the last half of 2008 with some improvement and high pricing volatility in 2009, 2010, and the first quarter of 2011. This pricing volatility has continued with natural gas prices while oil prices have seen significant improvement through the current period.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. We do not utilize these agreements and financial instruments for trading and only enter into derivative agreements with banks in our credit facility. Below is a description of the financial instruments we have utilized to hedge our exposure to price risk.

Price Floors - At March 31, 2011, we had natural gas price floors in effect that cover production of 3,915,000 MMBtu from April through June 2011 with strike prices ranging between $3.89 and $4.27 per MMBtu. We also had oil price floors in effect that cover production of 388,000 barrels of oil from April through May 2011 with strike prices ranging between $94.25 and $100.70 per barrel.

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. Continued volatility in both credit and commodity markets may reduce the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers and from certain customers we also obtain letters of credit, parent company guaranties if applicable, and other collateral as considered necessary to reduce risk of loss. Due to availability of other purchasers, we do not believe the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

Interest Rate Risk. Our senior notes and senior notes both have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At March 31, 2011, we had no borrowings under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 33 basis points and would not have a material adverse effect on our 2011 cash flows.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

We maintain disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, consisting of controls and other procedures designed to give reasonable assurance that information we are required to disclose in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to management, including our chief executive officer and our chief financial officer, to allow timely decisions regarding such required disclosure. The Company's chief executive officer and chief financial officer have evaluated such disclosure controls and procedures as of the end of the period covered by this quarterly report on Form 10-Q and have determined that such disclosure controls and procedures are effective.

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the first three months of 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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 2010 Annual Report on Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

The following table summarizes repurchases of our common stock occurring during the first quarter of 2011:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
01/01/11 – 01/31/11 (1)	60	$ 41.33	---	$ ---
02/01/11 – 02/28/11 (1)	74,939	$ 43.15	---	---
03/01/11 – 03/31/11 (1)	653	$ 40.17	---	---
Total	75,652	$ 43.12	---	$ ---

(1) These shares were withheld from employees to satisfy tax obligations arising upon the vesting of restricted shares.

Item 3. Defaults Upon Senior Securities.

None.

Item 5. Other Information.

None.

Item 6. Exhibits.

31.1*

	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	The following materials from the Company's quarterly Report on form 10-Q for the quarter ended March 31, 2011, formatted in Extensible Business Reporting Language (XBRL): (i) Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) Condensed Consolidated Statements of Stockholders' Equity, (iv) Condensed Consolidated Statements of Cash Flows, (v) Notes to Condensed Consolidated Financial Statements, tagged as blocks of text.

*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: May 5, 2011	By:	/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President and Chief Financial Officer
Date: May 5, 2011	By:	/s/ Barry S. Turcotte Barry S. Turcotte Vice President, Controller and Principal Accounting Officer

Exhibit Index

31.1* Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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32* Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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