SWIFT ENERGY CO
Form 10-Q
November 04, 2010

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

Form 10-Q

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

For the quarterly period ended September 30, 2010
Commission File Number 1-8754

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

Texas	20-3940661 (I.R.S. Employer
(State of Incorporation)	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.
YesþNo 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).
YesþNo 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	þ	Accelerated filer	o	Non-accelerated filer	o	Smaller reporting	o

filer company

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	37,885,357 Shares
($.01 Par Value)	(Outstanding at October
(Class of Stock)	31, 2010)

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SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2010

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

	September 30, 2010 (Unaudited)	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$5,508	$38,469
Accounts receivable	38,109	54,273
Deferred tax assets	6,208	3,171
Other current assets	16,086	12,123
Current assets held for sale	564	564
Total Current Assets	66,475	108,600
Property and Equipment:		
Oil and gas properties, using full-cost accounting	3,800,736	3,530,110
Less – Accumulated depreciation, depletion, and amortization	(2,333,367)	(2,214,146)
Property and Equipment, Net	1,467,369	1,315,964
Other Long-Term Assets	13,079	10,201
Total Assets	$1,546,923	$1,434,765
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$71,144	$60,823
Accrued capital costs	52,421	33,199
Accrued interest	10,139	3,745
Undistributed oil and gas revenues	4,950	5,837
Total Current Liabilities	138,654	103,604
Long-Term Debt	471,566	471,397
Deferred Income Taxes	150,803	123,577
Asset Retirement Obligation	58,650	55,298
Other Long-Term Liabilities	1,811	1,990
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, 38,322,622 and 37,887,126 shares issued, and 37,882,686 and 37,456,603 shares outstanding, respectively	383	379
Additional paid-in capital	562,429	551,606
Treasury stock held, at cost, 439,936 and 430,523 shares, respectively	(9,725)	(9,221)
Retained earnings	172,352	136,358
Accumulated other comprehensive loss, net of income tax	---	(223)
Total Stockholders' Equity	725,439	678,899

Total Liabilities and Stockholders' Equity	$1,546,923	$1,434,765

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		Nine Months Ended	
	09/30/10	09/30/09	09/30/10	09/30/09
Revenues:				
Oil and gas sales	$105,811	$97,952	$320,887	$257,153
Price-risk management and other, net	(165)	(1,689)	1,505	(1,610)
Total Revenues	105,646	96,263	322,392	255,543
Costs and Expenses:				
General and administrative, net	8,722	8,830	26,010	24,830
Depreciation, depletion, and amortization	40,800	41,011	118,103	125,310
Accretion of asset retirement obligation	998	732	2,927	2,151
Lease operating cost	20,977	18,513	59,561	57,139
Severance and other taxes	10,830	11,697	34,043	30,291
Interest expense, net	8,264	7,336	24,804	22,616
Write-down of oil and gas properties	---	---	---	79,312
Total Costs and Expenses	90,591	88,119	265,448	341,649
Income (Loss) from Continuing Operations Before Income Taxes	15,055	8,144	56,944	(86,106)
Provision (Benefit) for Income Taxes	5,652	586	20,788	(32,451)
Income (Loss) from Continuing Operations	9,403	7,558	36,156	(53,655)
Loss from Discontinued Operations, net of taxes	(73)	(32)	(162)	(215)
Net Income (Loss)	$9,330	$7,526	$35,994	$(53,870)
Per Share Amounts-				
Basic: Income (Loss) from Continuing Operations	$0.24	$0.21	$0.94	$(1.66)
Loss from Discontinued Operations, net of taxes	(0.00)	(0.00)	(0.00)	(0.01)
Net Income (Loss)	$0.24	$0.21	$0.93	$(1.67)
Diluted: Income (Loss) from Continuing Operations	$0.24	$0.21	$0.93	$(1.66)
Loss from Discontinued Operations, net of taxes	(0.00)	(0.00)	(0.00)	(0.01)
Net Income (Loss)	$0.24	$0.21	$0.93	$(1.67)
Weighted Average Shares Outstanding	37,880	34,723	37,792	32,310

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, 2008	$313	$435,307	$(10,431)	$175,688	$ -	$600,877
Stock issued for benefit plans (94,023 shares)	-	(716)	2,094	-	-	1,378
Stock options exercised (26,056 shares)	-	326	-	-	-	326
Public stock offering (6,210,000 shares)	62	108,689	-	-	-	108,751
Purchase of treasury shares (56,662 shares)	-	-	(884)	-	-	(884)
Tax benefits from stock compensation	-	(4,041)	-	-	-	(4,041)
Employee stock purchase plan (50,690 shares)	1	724	-	-	-	725
Issuance of restricted stock (263,908 shares)	3	(3)	-	-	-	-
Amortization of stock compensation	-	11,320	-	-	-	11,320
Net loss	-	-	-	(39,330)	-	(39,330)
Other comprehensive loss	-	-	-	-	(223)	(223)
Total comprehensive loss						(39,553)
Balance, December 31, 2009	$379	$551,606	$(9,221)	$136,358	$ (223)	$678,899
Stock issued for benefit plans (59,335 shares) (2)	-	242	1,271	-	-	1,513
Stock options exercised (63,298 shares) (2)	-	878	-	-	-	878
Purchase of treasury shares (68,748 shares) (2)	-	-	(1,775)	-	-	(1,775)
Employee stock purchase plan (66,564 shares) (2)	1	950	-	-	-	951
Issuance of restricted stock (305,634 shares) (2)	3	(3)	-	-	-	-
Amortization of stock compensation (2)	-	8,756	-	-	-	8,756
Net Income (2)	-	-	-	35,994	-	35,994
Other comprehensive income (2)	-	-	-	-	223	223
Total comprehensive income (2)						36,217
Balance, September 30, 2010 (2)	$383	$562,429	$(9,725)	$172,352	$ ---	$725,439

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

See accompanying Notes to Condensed Consolidated Financial Statements.

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

(in thousands)	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Cash Flows from Operating Activities:		
Net income (loss)	$35,994	$(53,870)
Plus loss from discontinued operations, net of taxes	162	215
Adjustments to reconcile net income (loss) to net cash provided by operation activities -		
Depreciation, depletion, and amortization	118,103	125,310
Write-down of oil and gas properties	---	79,312
Accretion of asset retirement obligation	2,927	2,151
Deferred income taxes	26,151	(21,927)
Stock-based compensation expense	7,550	6,854
Other	473	8,282
Change in assets and liabilities-		
Decrease in accounts receivable	1,837	2,874
Decrease in accounts payable and accrued liabilities	(5,812)	(4,119)
Decrease in income taxes payable	(38)	(293)
Increase in accrued interest	6,394	1,387
Cash provided by operating activities – continuing operations	193,741	146,176
Cash used in operating activities – discontinued operations	(29)	(366)
Net Cash Provided by Operating Activities	193,712	145,810
Cash Flows from Investing Activities:		
Additions to property and equipment	(228,379)	(164,504)
Proceeds from the sale of property and equipment	133	4,589
Cash used in investing activities – continuing operations	(228,246)	(159,915)
Cash provided by investing activities – discontinued operations	5,000	5,000
Net Cash Used in Investing Activities	(223,246)	(154,915)
Cash Flows from Financing Activities:		
Net payments of bank borrowings	---	(99,900)
Net proceeds from issuances of common stock	1,829	109,722
Purchase of treasury shares	(1,775)	(846)
Payments of debt issuance costs	(3,481)	---
Cash provided by (used in) financing activities – continuing operations	(3,427)	8,976
Cash provided by financing activities – discontinued operations	---	---
Net Cash Provided by (Used in) financing activities	(3,427)	8,976
Net decrease in Cash and Cash Equivalents	(32,961)	$(129)
Cash and Cash Equivalents at Beginning of Period	38,469	283
Cash and Cash Equivalents at End of Period	$5,508	$154
Supplemental Disclosures of Cash Flows Information:		

Cash paid during period for interest, net of amounts capitalized	$17,521	$20,190
Cash paid during period for income taxes	$168	$232

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, 2009 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 natural gas properties, with a focus on inland waters and onshore oil and natural gas reserves in Louisiana and Texas. Our undivided interests in gas processing plants 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 consolidated financial statements. There were no material subsequent events requiring additional disclosure in or amendments to 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 revenues, 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 nine months ended September 30, 2010 and 2009, such internal costs capitalized totaled $17.8 million and $18.1 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the nine months ended September 30, 2010 and 2009, capitalized interest on unproved properties totaled $5.5 million and $4.6 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.

Property and Equipment (in thousands)	September 30, 2010	December 31, 2009
Oil and gas properties, using full-cost accounting		
Proved properties	$3,684,549	$3,421,340
Unproved properties	78,878	71,640
Furniture, fixtures, and other equipment	37,309	37,130
Less – Accumulated depreciation, depletion, and amortization	(2,333,367)	(2,214,146)
Property and Equipment, Net	$1,467,369	$1,315,964

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 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. Under this method, we compute the provision by multiplying the total unamortized costs of oil and natural 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"). We did not have any hedges at September 30, 2010 that would materially affect this calculation. This calculation is done on a country-by-country basis.

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

As a result of low oil and natural gas prices at March 31, 2009, we reported a non-cash write-down on a before-tax basis of $79.3 million on our oil and natural gas properties.

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 additional 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, additional 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 September 30, 2010, 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 values of the bank borrowings approximate the carrying amounts as of September 30, 2010 and December 31, 2009, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of September 30, 2010 and December 31, 2009, the fair value of our senior notes due 2017, were $243.8 million, or 98% of face value, and 239.1 million, or 96% of face value, respectively. Based upon quoted market prices as of September 30, 2010 and December 31, 2009, the fair values of our senior notes due 2020, which were issued in November 2009, were $235.2 million, or 105% of face value and 234.0 million, or 104% of face value, respectively. The carrying value of our senior notes due 2017 was $250.0 million at September 30, 2010 and December 31, 2009, while the carrying value of our senior notes due 2020 was $221.6 million and $221.4 million at September 30, 2010 and December 31, 2009, 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 September 30, 2010 and December 31, 2009, 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 September 30, 2010 our “Accounts Receivable” balance included $35.3 million for oil and gas sales, $1.8 million for joint interest owners and $1.0 million for other receivables. At December 31, 2009 our “Accounts Receivable” balance included $36.4 million for oil and gas sales, $2.6 million for joint interest owners and $15.3 million for other receivables.

Insurance Claims. In 2008, we filed insurance claims related to 2008 Hurricanes Gustav and Ike. In April 2009, we settled our marine insurance claim relating to Hurricane Gustav for a net amount after deductible of $6.8 million, and in September 2009 settled our onshore claim relating to Hurricane Ike for a net amount after deductible of $0.8 million. Both of these reimbursements related to both capital costs and lease operating expense, and we have no additional hurricane related claims outstanding.

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 balance sheet as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the 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 third quarter of 2010 and 2009, we recognized a net loss of $0.2 million and a net loss of $1.3 million, respectively, relating to our derivative activities. During the first nine months of 2010 and 2009, we recognized a net gain of $0.8 million and a net loss of $1.3 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 September 30, 2010, the Company had no derivative gains or losses in "Accumulated other comprehensive loss, net of income tax" on the accompanying condensed consolidated balance sheet. The ineffectiveness reported in "Price-risk management and other, net" at September 30, 2010 and 2009 was not material.

At September 30, 2010, we did not have any outstanding derivative instruments in place for future production.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive income (loss), net of income tax." When the hedged transactions are recorded upon the actual sale of the oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive income (loss), net of income tax" on the accompanying condensed consolidated balance sheet and recorded in "Price-risk management and other, net" on the accompanying 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 September 30, 2010 and December 31, 2009, was zero and $0.8 million, respectively and was recognized on the accompanying condensed consolidated balance sheet in "Other current assets."

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees, 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 nine months of 2010 and 2009 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate was $9.2 million and $8.4

million in the first nine months of 2010 and 2009, 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 $12.5 million at September 30, 2010 and $10.0 million at December 31, 2009.

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 September 30, 2010, 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 2003, 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. Included in “Accounts payable and accrued liabilities,” on the accompanying condensed consolidated balance sheets, at September 30, 2010 and December 31, 2009 are liabilities of approximately $8.3 million and $7.5 million, respectively, which represent the amounts by which checks 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 September 30, 2010 and December 31, 2009 these assets include approximately $1.3 million in other long-term assets on the balance sheet. 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.

Accumulated Other Comprehensive Income (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 September 30, 2010, the Company had recorded no gains or losses in “Accumulated other comprehensive income (loss), net of income tax” on the accompanying condensed consolidated balance sheet. The components of accumulated other comprehensive income and related tax effects for 2010 were as follows (in thousands):

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2009	$(354)	$131	$(223)
Change in fair value of cash flow hedges	1,086	(400)	686
Effect of cash flow hedges settled during the period	(732)	269	(463)
Other comprehensive income at September 30, 2010	$---	$---	$---

Total comprehensive income was $9.3 million and $7.7 million for the third quarters of 2010 and 2009, respectively. Total comprehensive income (loss) was $36.2 million and ($53.9) million for the nine months of 2010 and 2009, 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)	2010	2009
Asset Retirement Obligation recorded as of January 1	$64,236	$48,785
Accretion expense	2,927	2,151
Liabilities incurred for new wells and facilities construction	1,018	3,302
Reductions due to sold and abandoned wells	(463)	(1,255)
Revisions in estimated cash flows	---	336
Asset Retirement Obligation as of September 30	$67,718	$53,319

At September 30, 2010 and December 31, 2009, approximately $9.1 million and $8.9 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 August 2009, we issued 6.21 million shares of our common stock in an underwritten public offering at a price of $18.50 per share. The gross proceeds from these sales were approximately $114.9 million, before deducting underwriting commissions and issuance costs totaling $6.1 million.

New Accounting Pronouncements. In January 2010, the FASB issued ASU 2010-03 to amend oil and gas reserve accounting and disclosure guidance that aligns the oil and gas reserve estimation and disclosure requirements of Topic 932 ("Extractive Industries – Oil and Gas") with the requirements of SEC Release No. 33-8995. This release is effective for financial statements issued on or after January 1, 2010. We have adopted this guidance for all reporting periods ending on or after December 31, 2009. This release changes the accounting and disclosure requirements surrounding oil and natural gas reserves and is intended to modernize and update the oil and gas disclosure requirements, to align them with current industry practices and to adapt to changes in technology. The most significant changes include:

- Changes to prices used in reserves calculations, for use in both disclosures and accounting impairment tests. Prices will no longer be based on a single-day, period-end price. Rather, they will be based on either the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements.
- Disclosure of probable and possible reserves is allowed.
- The estimation of reserves will allow the use of reliable technology that was not previously recognized by the SEC.
- Numerous changes in reserves disclosures mandated by SEC Form 10-K.
- Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

The change in prices used to calculate reserves did not have a material impact upon our reserves estimation in the current period. These changes could have a material impact upon our financial statements in future periods due to the uncertainty of oil and gas prices.

(3) Share-Based Compensation

We have various types of share-based compensation plans. Refer to Note 6 of our consolidated financial statements in our Annual Report on Form 10K for the fiscal year ended December 31, 2009, 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 nine months ended September 30, 2010, we did not recognize any excess tax benefit or shortfall. For the nine months ended September 30, 2009, we recognized a tax benefit shortfall of $2.3 million as restricted stock vested at a lower value than the value used to record compensation expense at the date of grant, offset by a reduction to additional paid-in capital.

Net cash proceeds from the exercise of stock options were $0.9 million and $0.2 million for the nine months ended September 30, 2010 and 2009. The actual income tax benefit from stock option exercises was $0.2 million for the nine months ended September 30, 2010 and less than $0.1 million for the nine months ended September 30, 2009.

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees, which were recorded in "General and administrative, net" in the accompanying condensed consolidated statements of operations, were $2.4 million and $2.1 million for the quarters ended September 30, 2010 and 2009, respectively, and were $6.9 million and $6.2 million for the nine month periods ended September 30, 2010 and 2009. Stock compensation recorded in lease operating cost was $0.1 million for the quarters ended September 30, 2010 and 2009, and was $0.3 million for the nine month periods ended September 30, 2010 and 2009. We also capitalized $0.4 million and $0.5 million of stock compensation in the third quarters of 2010 and 2009, respectively, and capitalized $1.2 million and $1.6 million of stock compensation in the nine month periods ended September 30, 2010 and 2009, 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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Dividend yield	N/A	N/A	0 %	0 %
Expected volatility	N/A	N/A	63.0 %	50.5 %
Risk-free interest rate	N/A	N/A	2.1 %	1.8 %
Expected life of options (in years)	N/A	N/A	4.3	4.5
Weighted-average grant-date fair value	N/A	N/A	$12.60	$6.32

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 2010 and 2009 stock option grants.

At September 30, 2010, we had $2.3 million of unrecognized compensation cost related to stock options, which is expected to be recognized over a weighted-average period of 1.1 years. The following table represents stock option activity for the nine months ended September 30, 2010:

	Shares	Wtd. Avg. Exercise Price
Options outstanding, beginning of period	1,289,194	$29.72
Options granted	267,378	$24.95
Options canceled	(36,983)	$44.65
Options exercised	(84,676)	$17.92
Options outstanding, end of period	1,434,913	$29.00
Options exercisable, end of period	828,666	$30.73

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at September 30, 2010 was $7.8 million and 5.7 years and $4.5 million and 3.9 years, respectively. Total intrinsic value of options exercised during the nine months ended September 30, 2010 was $1.1 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, 2009, 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 September 30, 2010, we had unrecognized compensation expense of $10.4 million related to restricted stock awards which is expected to be recognized over a weighted-average period of 1.1 years. The grant date fair value of shares vested during the nine months ended September 30, 2010 was $8.8 million.

The following table represents restricted stock activity for the nine months ended September 30, 2010:

	Shares		Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	703,856		$24.15
Restricted shares granted	375,450		$25.08
Restricted shares canceled	(37,633	)	$25.12
Restricted shares vested	(305,634	)	$28.87
Restricted shares outstanding, end of period	736,039		$22.65

(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 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. Unvested share-based payments that contain non-forfeitable rights to dividends or dividend equivalents are now included in the basic weighted average share calculation under the two-class method. These shares were previously included in the diluted weighted average share calculation under the treasury stock method.

Basic earnings per share ("Basic EPS") has been computed using the weighted average number of common shares outstanding during each period. As we recognized a net loss for the first nine months of 2009, the unvested share-based payments and stock options were not recognized in diluted earnings per share ("Diluted EPS") calculations as they would be antidilutive. Diluted EPS for the quarter ended September 30, 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 and nine month periods ended September 30, 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 and nine month periods ended September 30, 2010 and 2009 (in thousands, except per share amounts):

	Three Months Ended September 30, 2010			Three Months Ended September 30, 2009		
	Income from Continuing Operations	Shares	Per Share Amount	Income from Continuing Operations	Shares	Per Share Amount
Basic EPS:						
Income (Loss) from continuing operations, and Share Amounts	$9,403	37,880		$7,558	34,723	
Less: Income (Loss) from continuing operations allocated to unvested shareholders	(179)	---		(153)	---	
Income (Loss) from continuing operations allocated to common shares	$9,224	37,880	$0.24	$7,405	34,723	$0.21
Dilutive Securities:						
Plus: Income (Loss) from continuing operations allocated to unvested shareholders	179	---		153	---	
Less: Income (Loss) from continuing operations re-allocated to unvested shareholders	(178)	---		(152)	---	
Stock Options	---	178		---	110	
Diluted EPS:						
Income (Loss) from continuing operations allocated to common shares, and assumed share conversions	$9,225	38,058	$0.24	$7,406	34,833	$0.21

	Nine Months Ended September 30, 2010			Nine Months Ended September 30, 2009		
	Income from Continuing Operations	Shares	Per Share Amount	Income from Continuing Operations	Shares	Per Share Amount
Basic EPS:						
Income (Loss) from continuing operations, and Share Amounts	$36,156	37,792		$(53,655)	32,310	
Less: Income (Loss) from continuing operations allocated to unvested shareholders	(693)	---		---	---	
Income (Loss) from continuing operations allocated to common	$35,463	37,792	$0.94	$(53,655)	32,310	$(1.66)

shares						
Dilutive Securities:						
Plus: Income (Loss) from continuing operations allocated to unvested shareholders	693	---		---	---	
Less: Income (Loss) from continuing operations re-allocated to unvested shareholders	(689)	---		---	---	
Stock Options	---	203		---	---	
Diluted EPS:						
Income (Loss) from continuing operations allocated to common shares, and assumed share conversions	$35,467	37,995	$0.93	$(53,655)	32,310	$(1.66)

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Options to purchase approximately 1.4 million shares at an average exercise price of $29.00 were outstanding at September 30, 2010, while options to purchase approximately 1.3 million shares at an average exercise price of $29.56 were outstanding at September 30, 2009. Approximately 0.7 million and 0.9 million stock options to purchase shares were not included in the computation of Diluted EPS for both the three months ended September 30, 2010 and 2009, and 0.8 million options to purchase shares were not included in the computation of Diluted EPS for the nine months ended September 30, 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. For the nine month period ended September 30, 2009, all of the 1.3 million stock options to purchase shares outstanding were not included in the computation of Diluted EPS as they would be antidilutive given the net loss from continuing operations.

(5) Long-Term Debt

Our long-term debt as of September 30, 2010 and December 31, 2009, was as follows (in thousands):

	September 30, 2010	December 31, 2009
Bank Borrowings	$ ---	$ ---
7-1/8% senior notes due 2017	250,000	250,000
8-7/8% senior notes due 2020	221,566	221,397
Long-Term Debt	$ 471,566	$ 471,397

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 $1.6 million for the three months ended September 30, 2010 and 2009, respectively, and $5.5 million and $4.6 million for the nine month periods ended September 30, 2010 and 2009, 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 September 30, 2010 and December 31, 2009 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 September 30, 2010, 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. The borrowing base amount is re-determined at least every six months starting with the next scheduled borrowing base review in May 2011.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $0.5 million and $1.4 million for the three months ended September 30, 2010 and 2009, respectively, and $1.3 million and $4.6 million for the nine months ended September 30, 2010 and 2009, respectively. The amount of commitment fees included in interest expense, net was $0.4 million and $0.2 million for each of the three month periods ended September 30, 2010 and 2009, respectively, and $1.0 million and $0.4 million for each of the nine month periods ended September 30, 2010 and 2009.

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 a discount of $3.6 million and will mature on January 15, 2020. The discount of $3.6 million is recorded in “Long-Term Debt” on our balance sheet and will be amortized over the life of the note. 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 and $15.4 million for the three and nine months ended September 30, 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 September 30, 2010 and 2009, respectively, and $13.6 million for each of the nine month periods ended September 30, 2010 and 2009, respectively.

Senior Notes Due 2011. These notes consisted of $150.0 million of 7-5/8% senior subordinated notes due July 2011, which were issued on June 23, 2004 and which were fully redeemed as of December 10, 2009. In the fourth quarter of 2009, we recorded a charge of $4.0 million related to the redemption of these notes. The costs were comprised of approximately $2.9 million of premium paid to redeem the notes, and $1.1 million to write-off unamortized debt issuance costs.

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled $3.0 million and $9.0 million for the three and nine months periods ended September 30, 2009, respectively.

(6) Discontinued Operations

In December 2007, we agreed to sell substantially all of our New Zealand assets. Accordingly, the New Zealand operations have been classified as discontinued operations in the condensed consolidated statements of operations and cash flows and the assets and associated liabilities have been classified as held for sale in the condensed consolidated balance sheets. In June 2008, we completed the sale of substantially all of our New Zealand assets for $82.7 million in cash after purchase price adjustments. Proceeds from this asset sale were used to pay down a portion of our credit facility. 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. All payments under this sale agreement are secured by unconditional letters of credit, with the first two payments received in February 2009 and February 2010, respectively. 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 final resolution of this litigation.

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. Furthermore, the assets included as part of this divestiture have been reclassified as held for sale in the condensed consolidated balance sheets.

The book value of our remaining New Zealand permit is approximately $0.6 million at September 30, 2010.

The following table summarizes the amounts included in "Loss from Discontinued Operations, net of taxes" for all periods presented. These revenues and expenses were historically reported under our New Zealand operating segment, and are now reported as discontinued operations (in thousands except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Other revenues	$10	$10	$42	$30
Total revenues	10	10	42	30
Other operating expenses	$83	$42	$204	$245
Total expenses	83	42	204	245
Loss from discontinued operations before income taxes	$(73)	$(32)	$(162)	$(215)
Income tax expense (benefit)	---	---	---	---
Loss from discontinued operations, net of taxes	(73)	(32)	(162)	(215)
Loss per common share from discontinued operations-diluted	$(0.00)	$(0.00)	$(0.00)	$(0.01)
Cash flow used in operating activities	$(33)	$(29)	$(29)	$(366)

(7) Acquisitions and Dispositions

In August 2009, within our Central Louisiana/East Texas core area, we entered into a joint venture agreement with a large independent oil and gas producer active in the area for development and exploitation in and around the Burr Ferry field in Vernon Parish, Louisiana. The Company, as fee mineral owner, leased a 50% working interest in approximately 33,623 gross acres to the joint venture partner. Swift Energy retains a 50% working interest in the joint venture acreage as well as its fee mineral royalty rights, and received approximately $4.2 million related to this transaction. We used the proceeds from this joint venture to pay down a portion of the outstanding balance on our credit facility.

In November 2009, within our South Texas core area, we entered into a joint venture agreement with a large independent oil and gas producer active in the area for development and exploitation in and around the Eagle Ford Shale in McMullen County, Texas. The Company leased a 50% working interest in approximately 26,000 gross acres to the joint venture partner. Swift Energy retains a 50% working interest in the joint venture acreage and received approximately $26 million in cash consideration as well as consideration for approximately $13 million to fund future capital expenditures in the joint venture agreement, related to this transaction. As of September 30, 2010 we had approximately $0.1 million of the $13 million consideration remaining in our balance sheet. We used the proceeds from this joint venture to pay down a portion of the outstanding balance on our credit facility.

(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 September 30, 2010 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 September 30, 2010			
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	$3.9	$3.9	$---	$ ---

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) and contain inputs such as contract prices, risk-free rates, volatility measurements and other observable market data, which 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 subordinated notes due 2017 and 2020. The guarantees on our senior subordinated notes due 2017 and 2020 are full and unconditional and joint and several. The following is condensed consolidating financial information for Swift Energy Company, Swift Energy Operating, LLC, and other subsidiaries:

Condensed Consolidating Balance Sheets

(in thousands) September 30, 2010

	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
ASSETS					
Current assets	$---	$65,877	$598	$---	$ 66,475
Property and equipment	---	1,467,369	---	---	1,467,369
Investment in subsidiaries (equity method)	725,439	---	654,183	(1,379,622)	---
Other assets	---	13,079	80,732	(80,732)	13,079
Total assets	$725,439	$1,546,325	$735,513	$(1,460,354)	$ 1,546,923
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$---	$128,580	$10,074	$---	$ 138,654
Long-term liabilities	---	763,562	---	(80,732)	682,830
Stockholders' equity	725,439	654,183	725,439	(1,379,622)	725,439
Total liabilities and stockholders' equity	$725,439	$1,546,325	$735,513	$(1,460,354)	$ 1,546,923

(in thousands) December 31, 2009

	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
ASSETS					
Current assets	$---	$102,975	$5,625	$---	$ 108,600
Property and equipment	---	1,315,964	---	---	1,315,964
Investment in subsidiaries (equity method)	678,899	---	602,483	(1,281,382)	---
Other assets	---	10,201	75,850	(75,850)	10,201
Total assets	$678,899	$1,429,140	$683,958	$(1,357,232)	$ 1,434,765
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$---	$98,545	$5,059	$---	$ 103,604
Long-term liabilities	---	728,112	---	(75,850)	652,262
Stockholders' equity	678,899	602,483	678,899	(1,281,382)	678,899
Total liabilities and stockholders' equity	$678,899	$1,429,140	$683,958	$(1,357,232)	$ 1,434,765

Condensed Consolidating Statements of Income

(in thousands)	Three Months Ended September 30, 2010				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Revenues	$---	$105,646	$---	$ ---	$ 105,646
Expenses	---	90,591	---	---	90,591
Income before the following:	---	15,055	---	---	15,055
Equity in net earnings of subsidiaries	9,330	---	9,403	(18,733)	---
Income from continuing operations, before income taxes	9,330	15,055	9,403	(18,733)	15,055
Income tax provision	---	5,652	---	---	5,652
Income from continuing operations	9,330	9,403	9,403	(18,733)	9,403
Loss from discontinued operations, net of taxes	---	---	(73)	---	(73)
Net income	$9,330	$9,403	$9,330	$ (18,733)	$ 9,330

(in thousands)	Nine Months Ended September 30, 2010				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Revenues	$---	$322,392	$---	$ ---	$ 322,392
Expenses	---	265,448	---	---	265,448
Income before the following:	---	56,944	---	---	56,944
Equity in net earnings of subsidiaries	35,994	---	36,156	(72,150)	---
Income from continuing operations, before income taxes	35,994	56,944	36,156	(72,150)	56,944
Income tax provision	---	20,788	---	---	20,788
Income from continuing operations	35,994	36,156	36,156	(72,150)	36,156
Loss from discontinued operations, net of taxes	---	---	(162)	---	(162)

Net income	$35,994	$36,156	$35,994	$ (72,150)	$ 35,994

(in thousands)	Three Months Ended September 30, 2009				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Revenues	$---	$96,263	$---	$ ---	$ 96,263
Expenses	---	88,119	---	---	88,119
Income before the following:	---	8,144	---	---	8,144
Equity in net earnings of subsidiaries	7,526	---	7,558	(15,084)	---
Income from continuing operations, before income taxes	7,526	8,144	7,558	(15,084)	8,144
Income tax provision	---	586	---	---	586
Income from continuing operations	7,526	7,558	7,558	(15,084)	7,558
Loss from discontinued operations, net of taxes	---	---	(32)	---	(32)
Net Loss	7,526	7,558	7,526	$ (15,084)	7,526

(in thousands)	Nine Months Ended September 30, 2009				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Revenues	$---	$255,543	$---	$ ---	$ 255,543
Expenses	---	341,649	---	---	341,649
Loss before the following:	---	(86,106)	---	---	(86,106)
Equity in net earnings of subsidiaries	(53,870)	---	(53,655)	107,525	---
Loss from continuing operations, before income taxes	(53,870)	(86,106)	(53,655)	107,525	(86,106)
Income tax benefit	---	(32,451)	---	---	(32,451)
Loss from continuing operations	(53,870)	(53,655)	(53,655)	107,525	(53,655)
Loss from discontinued operations, net of taxes	---	---	(215)	---	(215)
Net Loss	$(53,870)	$(53,655)	$(53,870)	$ 107,525	$ (53,870)

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Condensed Consolidating Statements of Cash Flow

(in thousands) Nine Months Ended September 30, 2010

	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Cash flow from operations	$---	$193,741	$(29)	$ ---	$ 193,712
Cash flow from investing activities	---	(223,246)	5,000	(5,000)	(223,246)
Cash flow from financing activities	---	(3,427)	(5,000)	5,000	(3,427)
Net decrease in cash	---	(32,932)	(29)	---	(32,961)
Cash, beginning of period	---	38,405	64	---	38,469
Cash, end of period	$---	$5,473	$35	$ ---	$ 5,508

(in thousands) Nine Months Ended September 30, 2009

	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Cash flow from operations	$---	$146,176	(366)	$ ---	$ 145,810
Cash flow from investing activities	---	(155,170)	5,000	(4,745)	(154,915)
Cash flow from financing activities	---	8,976	(4,745)	4,745	8,976
Net decrease in cash	---	(18)	(111)	---	(129)
Cash, beginning of period	---	87	196	---	283
Cash, end of period	$---	$69	$85	$ ---	$ 154

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 condensed consolidated financial statements and notes thereto included in this report and our Annual Report on Form 10-K for the year ended December 31, 2009. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 34 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 the inland waters of Louisiana and from our onshore Louisiana and Texas properties.

We are one of the largest producers of crude oil in the state of Louisiana, due to our South Louisiana operations. Oil production accounted for 49% of our third quarter of 2010 production, and combined oil and natural gas liquids production ("NGLs") made up 61% of our third quarter of 2010 production. This emphasis has allowed us to benefit from better margins for oil production than natural gas production during 2010.

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.

2010 Oil and Natural Gas Pricing

Increased prices for oil, natural gas, and NGLs in 2010 have had a positive impact on our cash flow, earnings, and liquidity when compared to the same period in 2009. Oil and NGL prices we received for the first nine months of 2010 were 41% and 49% higher, respectively, than the average prices we received in the same period of 2009, while natural gas prices increased 21% in the 2010 period. Prices for oil and NGLs in the third quarter of 2010 declined slightly when compared to prices in the second quarter of 2010, as oil prices declined 2% and NGL prices decreased 5%, while natural gas prices increased 4%.

Financial Condition

In September 2010, we renewed and extended our $500.0 million credit facility with a syndicate of nine banks through October 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.

We raised $108.8 million through an underwritten public stock offering in August 2009. We issued 6.21 million shares of our common stock at a price of $18.50 per share. The gross proceeds from these sales were approximately $114.9 million, before deducting underwriting commissions and issuance costs totaling $6.1 million.

In November 2009, we issued $225.0 million of 8-7/8% senior notes due 2020 at 98.389% of par, which equates to an effective yield to maturity of 9-1/8%. In December 2009, we redeemed all $150.0 million of our 7-5/8% senior notes due 2011 and recorded a charge of $4.0 million related to the redemption of these notes, which is recorded in "Debt Retirement Costs" on the accompanying condensed consolidated statement of operations. The costs were comprised of approximately $2.9 million of premium paid to redeem the notes, and $1.1 million to write-off unamortized debt issuance costs.

We used the net proceeds from this stock sale and note offering, less costs to redeem our senior notes due 2011, to pay down the outstanding balance on our credit facility. At December 31, 2009 and September 30, 2010, we had no amounts drawn under our credit facility.

Our net debt to capitalization ratio was unchanged from year-end 2009, and was 39% at both September 30, 2010 and at year-end 2009.

Operating Results – Prior Year Comparison

In the third quarter of 2010 we had revenues of $105.6 million, an increase of 10% compared to revenues in the same quarter in 2009. Our weighted average price received increased 16% to $51.06 per Boe received for the third quarter of 2010 from $44.14 per Boe in the 2009 period. This $9.4 million increase in revenues from 2009 levels resulted from higher oil, natural gas, and NGL prices during the third quarter of 2010, offset partially by a 7% decrease in production mainly due to natural declines in our Southeast Louisiana core area.

Our overall costs and expenses increased in the third quarter of 2010 by $2.5 million when compared to costs incurred in the same period in 2009. Lease operating costs increased by 13%, or $2.5 million, due to additional workovers and higher environmental and chemical treating costs. Severance and other taxes decreased 7%, or $0.9 million, mainly due to increased production in Texas with a lower severance burden than Louisiana.

Our income from continuing operations for the third quarter of 2010 was $9.4 million and was $7.6 million for the 2009 period, with the increase due primarily to higher revenue from higher commodity prices.

Operating Activities

In our South Texas core area, we drilled nine operated and two non-operated horizontal wells during the third quarter. Six were Eagle Ford wells, of which two were non-operated. In the Olmos, we drilled five horizontal wells. One of the Olmos wells was abandoned due to mechanical reasons, and it will be completed as a water source well. As of September 30th, a total of twelve horizontal wells were waiting on completion. Four of these wells were completed in October. Fracturing operations to complete the remaining wells are ongoing.

In South Texas, we also drilled five vertical Olmos wells. Three of these wells were completed during the third quarter, one was completed in October and one remains to be completed. We performed six fracture enhancements during the quarter and two in October. We plan to perform two additional vertical well fracture enhancement operations before year-end.

Our undeveloped Eagle Ford Shale position encompassed 92,322 gross and 78,315 net acres in our South Texas region. A portion of this Eagle Ford acreage is below existing Olmos acreage that we also hold.

We plan to obtain a total of 304 square miles of additional 3D seismic data which includes 79 square miles of existing non-exclusive 3D seismic and 225 square miles of new, non-exclusive 3D seismic. To date we have taken delivery of approximately 230 square miles that have been provisionally merged into our existing 3D database. We anticipate delivery of the remaining 74 square miles of data before the end of 2010. These data will be reprocessed and merged into a continuous 700 square mile 3D volume that will be utilized to explore and develop our assets in and around the AWP area.

In our Southeast Louisiana core area, four wells were drilled in the Lake Washington field. Three of these wells were completed during the third quarter and the fourth well was unsuccessful. Four additional wells are scheduled for the remainder of 2010. One well was returned to production after being shut in, and two wells were re-completed during the third quarter of 2010. Between two and four more recompletions are planned for the remainder of 2010. Other production enhancement activity included two gas lift modifications, five sliding sleeve changes, one water shutoff, and 8 choke changes.

In Central Louisiana we drilled and completed one non-operated horizontal well in our South Burr Ferry Field. This well was waiting on completion of production facilities and is expected to be on-line in early November.

We have 4,000 square miles of proprietary merged and prestack depth-migrated ("PSDM") 3D seismic data over our Southeast Louisiana and South Louisiana core areas. The use of these PSDM data has significantly improved and refined our understanding of the hydrocarbon traps associated with the complex salt bodies, faulting and overpressure that are evident in this province. These data enable us to more accurately plan and position our exploratory and development wells. The improved seismic image in our Southeast Louisiana and South Louisiana core areas described above has delivered additional high value prospects which could be drilled in future periods depending upon the commodity pricing environment.

Capital Expenditures

Our capital expenditures on an accrual basis were $270.6 million in the first nine months of 2010, which was an increase from $95.1 million spent on an accrual basis in the 2009 period. The increase in the 2010 period was mainly due to additional drilling activity in our South Texas region. These 2010 expenditures were primarily funded by $193.7 million of cash provided by operating activities from continuing operations, the use of cash on hand, the use of $12.5 million in carried interests from our Eagle Ford joint venture operations, and $5.0 million of cash provided from our discontinued operations.

We currently plan to fund our 2010 capital expenditures with our 2010 cash flow, cash on hand, and availability under our credit facility. Our 2010 capital expenditures are currently budgeted at $370 million to $390 million, net of minor non-core dispositions. These expenditures are expected to include: i) a continuation of the horizontal well drilling program in the Olmos sands, an ongoing horizontal well program in the Eagle Ford shale formation and the fracture enhancement and artificial lift programs in our South Texas core area, ii) focus on recompletions and facility optimization in our Southeast Louisiana area and iii) one non-operated well being brought on-line and the completion of another non-operated well (both in November) and the completion of both an operated and non-operated well in December in our Central Louisiana/East Texas area.

Results of Continuing Operations — Three Months Ended September 30, 2010 and 2009

Revenues. Our revenues in the third quarter of 2010 increased by 10% compared to revenues in the same period in 2009, due to higher oil, natural gas, and NGL prices. Crude oil production was 49% of our production volumes in both third quarter periods and natural gas production was 39% of our production volumes in both third quarter periods.

Our properties are divided into core areas. The Southeast Louisiana core area includes the Lake Washington and Bay de Chene fields. The South Texas core area includes the AWP, Briscoe Ranch, Las Tiendas, and Sun TSH fields. The Central Louisiana/East Texas core area includes the Brookeland, Masters Creek, South Bearhead Creek, and Chunchula fields. The South Louisiana core area includes the Cote Blanche Island, Horseshoe Bayou/Bayou Sale, Jeanerette, High Island, and Bayou Penchant fields. The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the three months ended September 30, 2010 and 2009:

Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2010	2009	2010	2009
S. E. Louisiana	$60.2	$65.4	934	1,224
South Texas	29.0	16.9	796	635
Central Louisiana / E. Texas	10.0	10.0	192	212
South Louisiana	6.4	5.5	145	141
Other	0.2	0.2	5	7
Total	$105.8	$98.0	2,072	2,219

Oil and gas sales for the third quarter of 2010 increased by 8%, or $7.9 million, from the level of those revenues for the comparable 2009 period, and our net production volumes in the third quarter of 2010 decreased by 7%, or 0.1 MMBoe, compared to net production volumes in the third quarter of 2009. Average prices for oil increased to $76.39 per Bbl in the third quarter of 2010 from $68.15 per Bbl in the third quarter of 2009. Average natural gas prices increased to $3.87 per Mcf in the third quarter of 2010 from $2.84 per Mcf in the third quarter of 2009. Average NGL prices increased to $39.88 per Bbl in the third quarter of 2010 from $35.09 per Bbl in the third quarter of 2009.

In the third quarter of 2010, our $7.9 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $14.6 million favorable impact on sales, of which $8.3 million was attributable to the 12% increase in average oil prices received, $1.2 million was attributable to the 14% increase in NGL prices, and $5.0 million was attributable to the 36% increase in natural gas prices; and
- Volume variances that had a $6.7 million unfavorable impact on sales, with a $5.0 million decrease attributable to the less than 0.1 million Bbl decrease in oil production volumes, an $0.8 million decrease due to the less than 0.1 million Bbl decrease in NGL production volumes and a $0.9 million decrease due to the 0.3 Bcf decrease in natural gas production volumes. The declines in production volumes were mainly due to natural declines in our Southeast Louisiana core area.

The following table provides additional information regarding our quarterly oil and gas sales from continuing operations 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 September 30, 2010	1,005	256	4.9	2,072	$ 76.39	$ 39.88	$ 3.87
Three Months Ended September 30, 2009	1,078	279	5.2	2,219	$ 68.15	$ 35.09	$ 2.84

During the third quarter of 2010, we recorded a net loss of $0.2 million related to our derivative activities, while during the third quarter of 2009 we recorded a net loss of $1.3 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 $76.44 and $66.97 for the third quarters of 2010 and 2009, respectively, and our average natural gas price would have been $3.81 and $2.84 for the third quarters of 2010 and 2009, respectively.

Costs and Expenses. Our expenses in the third quarter of 2010 increased $2.5 million, or 3%, compared to expenses in the same period of 2009, principally due to higher lease operating costs.

Our third quarter 2010 general and administrative expenses, net, decreased $0.1 million, or 1%, from the level of such expenses in the same 2009 period. For the third quarters of 2010 and 2009, our capitalized general and administrative costs totaled $5.9 million and $6.0 million, respectively. Our net general and administrative expenses per Boe produced increased to $4.21 per Boe in the third quarter of 2010 from $3.98 per Boe in the third quarter of 2009. The portion of supervision fees recorded as a reduction to general and administrative expenses was $3.2 million and $2.7 million for three month periods ended September 30, 2010 and 2009, respectively.

DD&A decreased $0.2 million, or 1%, in the third quarter of 2010, from levels in the third quarter of 2009. The decrease was primarily due to lower production and higher reserves volumes, partially offset by higher future development costs. Our DD&A rate per Boe of production was $19.69 and $18.48 in the third quarters of 2010 and 2009, respectively.

We recorded $1.0 million and $0.7 million in accretion of our asset retirement obligation in the third quarters of 2010 and 2009, respectively.

Our lease operating costs increased $2.5 million, or 13%, compared to the level of such expenses in the same 2009 period. Lease operating costs increased as a result of higher workover and environmental clean-up costs. Our lease operating costs per Boe produced were $10.12 and $8.34 in the third quarters of 2010 and 2009, respectively.

Severance and other taxes decreased $0.9 million, or 7%, from levels in the third quarter of 2009. The decrease in the 2010 period was 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. Severance and other taxes as a percentage of oil and gas sales were approximately 10.2% and 11.9% in the third quarters of 2010 and 2009, respectively.

Our gross interest cost in the third quarter of 2010 was $10.1 million, of which $1.9 million was capitalized. Our gross interest cost in the third quarter of 2009 was $8.9 million, of which $1.6 million was capitalized. We capitalize a portion of interest related to unproved properties. The increase in interest expense during the third quarter of 2010 was primarily due to interest on our new $225 million senior notes which bear a higher interest rate than the debt that was retired in the fourth quarter of 2009.

Our overall effective tax rate was 37.5% and 7.2% for the third quarters of 2010 and 2009, respectively. The third quarter 2009 rate included a year-to-date cumulative effective rate decrease.

Income from Continuing Operations. Our income from continuing operations for the third quarter of 2010 of $9.4 million was higher than the third quarter 2009 income from continuing operations of $7.6 million primarily due to higher revenue as a result of higher commodity prices.

Net Income. We had net income in the third quarter of 2010 of $9.3 million, due to higher revenue as a result of higher commodity prices when compared to net income in the third quarter of 2009 of $7.5 million.

Results of Continuing Operations — Nine months Ended September 30, 2010 and 2009

Revenues. Our revenues in the first nine months of 2010 increased by 26% compared to revenues in the same period in 2009, primarily due to higher commodity prices, partially offset by lower production volumes. Crude oil production was 48% of our production volumes in the first nine months of 2010 and 47% of our production in the first nine months of 2009. Natural gas production was 39% of our production volumes in the first nine months of 2010 and 40% in the first nine months of 2009.

The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the nine months ended September 30, 2010 and 2009:

Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2010	2009	2010	2009
S. E. Louisiana	$183.4	$158.9	2,814	3,584
South Texas	86.3	54.4	2,318	2,059
Central Louisiana / E. Texas	28.9	26.8	527	672
South Louisiana	21.8	16.7	468	504
Other	0.5	0.4	18	22
Total	$320.9	$257.2	6,145	6,841

Oil and gas sales for the first nine months of 2010 increased by 25%, or $63.7 million, from the level of those revenues for the comparable 2009 period, and our net production volumes in the first nine months of 2010 decreased by 10%, or 0.7 MMBoe, compared to net production volumes in the first nine months of 2009. Average prices for oil increased to $77.42 per Bbl in the first nine months of 2010 from $54.77 per Bbl in the first nine months of 2009. Average natural gas prices increased to $4.11 per Mcf in the first nine months of 2010 from $3.40 per Mcf in the first nine months of 2009. Average NGL prices increased to $42.31 per Bbl in the first nine months of 2010 from $28.42 per Bbl in the first nine months of 2009.

In the first nine months of 2010, our $63.7 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $88.1 million favorable impact on sales, of which $66.4 million was attributable to the 41% increase in average oil prices received, $11.6 million was attributable to the 49% increase in NGL prices, and $10.1 million was attributable to the 21% increase in natural gas prices; and
- Volume variances that had a $24.4 million unfavorable impact on sales, with a $15.5 million decrease attributable to the 0.3 million Bbl decrease in oil production volumes, a $1.6 million decrease due to the less than 0.1 million Bbl decrease in NGL production volumes and a $7.3 million decrease due to the 2.1 Bcf decrease in natural gas production volumes. The declines in production volumes were mainly due to natural declines in our Southeast Louisiana core area.

The following table provides additional information regarding our quarterly oil and gas sales from continuing operations 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)
Nine Months Ended September 30, 2010	2,929	839	14.3	6,145	$ 77.42	$ 42.31	$ 4.11
Nine Months Ended September 30, 2009	3,213	894	16.4	6,841	$ 54.77	$ 28.42	$ 3.40

During the first nine months of 2010, we recorded a net gain of $0.8 million related to our derivative activities. During the first nine months of 2009 we recorded a net loss of $1.3 million. This activity is recorded in "Price-risk management and other, net" on the accompanying condensed consolidated statements of operations. Had these gains (losses) been recognized in the oil and gas sales account, our average oil price would have been $77.53 and $54.37 for the first nine months of 2010 and 2009, respectively, and our average natural gas price would have been $4.15 and $3.40 for the first nine months of 2010 and 2009, respectively.

Costs and Expenses. Our expenses in the first nine months of 2010 decreased $76.2 million, or 22%, compared to expenses in the same period of 2009, principally due to a 2009 non-cash write-down on a before-tax basis of $79.3 million ($50.0 million after tax) on our oil and gas properties as a result of lower oil and natural gas prices at March 31, 2009.

Our first nine months 2010 general and administrative expenses, net, increased $1.2 million, or 5%, from the level of such expenses in the same 2009 period primarily due to higher office rent. For the first nine months of 2010 and 2009, our capitalized general and administrative costs totaled $17.5 million and $18.1 million, respectively. Our net general and administrative expenses per Boe produced increased to $4.23 per Boe in the first nine months of 2010 from $3.63 per Boe in the first nine months of 2009. The portion of supervision fees recorded as a reduction to general and administrative expenses was $9.2 million and $8.4 million for three month periods ended September 30, 2010 and 2009, respectively.

DD&A decreased $7.2 million, or 6%, in the first nine months of 2010, from levels in the first nine months of 2009. The decrease was primarily due to lower production and higher reserves volumes. Our DD&A rate per Boe of production was $19.22 and $18.32 in the first nine months of 2010 and 2009, respectively.

We recorded $2.9 million and $2.2 million in accretion of our asset retirement obligation in the first nine months of 2010 and 2009, respectively.

Our lease operating costs increased $2.4 million, or 4%, compared to the level of such expenses in the same 2009 period. Lease operating costs increased as a result of higher workover, salt water disposal, and gas processing costs. Our lease operating costs per Boe produced were $9.69 and $8.35 in the first nine months of 2010 and 2009, respectively.

Severance and other taxes increased $3.8 million, or 12%, from levels in the first nine months of 2009. The increase in the 2010 period was due primarily to higher revenue as a result of higher commodity prices. Severance and other taxes as a percentage of oil and gas sales were approximately 10.6% and 11.8% in the first nine months of 2010 and 2009, respectively, with the decrease due to reductions in ad valorem taxes in the 2010 period and reduced tax rates for tight sand gas production related to South Texas Olmos and Eagleford completions.

Our gross interest cost in the first nine months of 2010 was $30.3 million, of which $5.5 million was capitalized. Our gross interest cost in the first nine months of 2009 was $27.2 million, of which $4.6 million was capitalized. We capitalize a portion of interest related to unproved properties. The increase in interest expense during the first nine months of 2010 was primarily due to interest on our new $225 million senior notes which bear a higher interest rate than the debt that was retired in the fourth quarter of 2009.

Our overall effective tax rate was 36.5% and 37.7% for the first nine months of 2010 and 2009, respectively. The effective tax rate for the first nine months of 2010 and 2009 was higher than the U.S. federal statutory rate of 35% primarily because of state income taxes.

Income (Loss) from Continuing Operations. Our income from continuing operations for the first nine months of 2010 of $36.2 million was higher than the first nine months 2009 loss from continuing operations of $53.7 million primarily due to the non-cash write-down of oil and gas properties in the first nine months of 2009.

Net Income (Loss). We had net income in the first nine months of 2010 of $36.0 million and had a net loss of $53.9 million in the first nine months of 2009.

Discontinued Operations

In December 2007, Swift Energy agreed to sell substantially all of our New Zealand assets. Accordingly, the New Zealand operations have been classified as discontinued operations in the condensed consolidated statements of operations and cash flows and the assets and associated liabilities have been classified as held for sale in the condensed consolidated balance sheets. In June 2008, Swift Energy completed the sale of substantially all of our New Zealand assets for $82.7 million in cash after purchase price adjustments. Proceeds from this asset sale were used to pay down a portion of our credit facility. 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 six months after the sale, 18 months after the sale, and 30 months after the sale. All payments under this sale agreement are secured by unconditional letters of credit, with the first two payments received in February 2009 and February 2010, respectively. 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 final resolution of this litigation.

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. Furthermore, the assets included as part of this divestiture have been reclassified as held for sale in the condensed consolidated balance sheets.

The following table summarizes the amounts included in "Loss from Discontinued Operations, net of taxes" for all periods presented. These revenues and expenses were historically reported under our New Zealand operating segment, and are now reported as discontinued operations (in thousands except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Other revenues	$10	$10	$42	$30
Total revenues	10	10	42	30
Other operating expenses	$83	$42	$204	$245
Total expenses	83	42	204	245
Loss from discontinued operations before income taxes	$(73)	$(32)	$(162)	$(215)
Income tax expense (benefit)	---	---	---	---
Loss from discontinued operations, net of taxes	(73)	(32)	(162)	(215)
Loss per common share from discontinued operations-diluted	$(0.00)	$(0.00)	$(0.00)	$(0.01)
Cash flow used in operating activities	$(33)	$(29)	$(29)	$(366)

Share-Based Compensation

We follow guidance contained in FASB ASC 718 (formerly SFAS No. 123R) to account for share-based compensation. 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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Dividend yield	N/A	N/A	0 %	0 %
Expected volatility	N/A	N/A	63.0 %	50.5 %
Risk-free interest rate	N/A	N/A	2.1 %	1.8 %
Expected life of options (in years)	N/A	N/A	4.3	4.5
Weighted-average grant-date fair value	N/A	N/A	$12.60	$6.32

The expected term for grants issued is based on an analysis of historical employee exercise behavior and considered all relevant factors including 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 2010 and 2009 stock option grants.

At September 30, 2010, there was $2.3 million of unrecognized compensation cost related to stock options, which is expected to be recognized over a weighted-average period of 1.1 years, and unrecognized compensation expense of $10.4 million related to restricted stock awards which is expected to be recognized over a weighted-average period of 1.1 years. The compensation expense for restricted stock awards was determined based on the market price of our stock at the date of grant applied to the total numbers of shares that were anticipated to fully vest.

Contractual Commitments and Obligations

We have negotiated several new contracts for drilling and completion services. As of September 30, 2010 our financial commitments under these contracts are approximately $19 million for the remainder of 2010, $74 million for 2011, and $25 million for 2012. We have had no other material changes to 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, 2009.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and this volatility is expected to continue in future periods. The price of oil declined significantly from 2008 into the first quarter of 2009, however, oil prices made some improvement in the later part of 2009 and through 2010. 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 remained high during much of 2008 when compared to longer-term historical prices but began falling in 2008 and continued to fall throughout 2009, showing slight improvement in late 2009 and through 2010. 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.

Operational Risk Management

Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and natural gas, including blowouts, cratering, pipe failure, casing collapse, fires, and adverse weather conditions, each of which could result in severe damage to or destruction of oil and natural gas wells, production facilities or other property, or individual injuries. The oil and natural gas exploration business is also subject to environmental hazards, such as oil spills, natural gas leaks, and ruptures and discharges of toxic substances or gases that could expose us to substantial liability due to pollution and other environmental damage. See “1A. Risk Factors” in our Annual Report on Form 10-K filed for the fiscal year ended December 31, 2009 for more details and for discussion of other risks. We maintain comprehensive insurance coverage, including general liability insurance and property damage insurance. We believe that our insurance is adequate and customary for companies of a similar size engaged in comparable operations, but if a significant accident or other event occurs that is uninsured or not fully covered by insurance, it could adversely affect us.

Income Taxes

The tax laws in the jurisdictions we operate in are continuously changing and professional judgments regarding such tax laws can differ. 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.

Liquidity and Capital Resources

Previous extreme volatility in worldwide credit and financial markets, combined with previous extreme volatility in prices for oil and natural gas, all of which began in 2008, may continue to have a significant impact on our cash flow, capital expenditures, and liquidity in future periods. See “Overview – Financial Condition.”

Net Cash Provided by Operating Activities. For the first nine months of 2010, our net cash provided by operating activities from continuing operations was $193.7 million, representing a 33% increase as compared to $146.2 million generated during the 2009 period. The $47.6 million increase in 2010 was primarily due to an increase of $63.7 million in oil and gas sales, attributable to higher oil and natural gas prices, partially offset by lower production.

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 both September 30, 2010 and December 31, 2009, 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” balances on the accompanying condensed consolidated balance sheets.

Existing Credit Facility. We had no borrowings under our bank credit facility at September 30, 2010, or at December 31, 2009. In September 2010 we renewed and extended our $500.0 million credit facility through October 2015. We also increased our borrowing base to $300.0 million from 277.5 million. The next scheduled borrowing base review occurs in May 2011.

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, many financial institutions have experienced liquidity issues, and governments have intervened in these markets to create liquidity. We have reviewed the creditworthiness of the banks that fund our credit facility. However, if the current credit market volatility is prolonged, future extensions of our credit facility may contain terms and interest rates not as favorable as those of our current credit facility.

Working Capital. Our working capital decreased from a surplus of $5.0 million at December 31, 2009, to a deficit of $72.2 million at September 30, 2010. The change primarily resulted from a decrease in cash and cash equivalents, an increase in accounts payable and accrued liabilities plus an increase in accrued capital costs all of which are related to additional drilling activity in South Texas during 2010. We also had an increase in accrued interest related to our new Senior Notes due 2020 and a decrease in other receivables from the use of our drilling consideration with our joint venture partner in South Texas. 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.

Debt Maturities. Our credit facility, which had no balance at September 30, 2010, expires on October 15, 2015. Our $250.0 million of 7-1/8% senior notes mature June 1, 2017, and our $225.0 million of 8-7/8% senior notes mature January 15, 2020.

Cash Used in Investing Activities. For the first nine months of 2010 our oil and gas property additions were $228.4 million. This amount increased by $63.9 million as compared to our oil and gas property additions during the first nine months of 2009, primarily due to an increase in spending on drilling and development in our South Texas area, partially offset by a decrease in our spending on drilling and development in our Southeast Louisiana core area. These 2010 expenditures were funded by $193.7 million of cash provided by operating activities from continuing operations. We drilled 34 operated and six non-operated wells during the first nine months of 2010.

New Accounting Pronouncements

New Accounting Pronouncements. In January 2010, the FASB issued ASU 2010-03 to amend oil and gas reserve accounting and disclosure guidance that aligns the oil and gas reserve estimation and disclosure requirements of Topic

932 (“Extractive Industries – Oil and Gas”) with the requirements of SEC release 33-8995. These releases are effective for financial statements issued on or after January 1, 2010. We have adopted this guidance for all reporting periods ending on or after December 31, 2009. This release changes the accounting and disclosure requirements surrounding oil and natural gas reserves and is intended to modernize and update the oil and gas disclosure requirements, to align them with current industry practices and to adapt to changes in technology. The most significant changes include:

- Changes to prices used in reserves calculations, for use in both disclosures and accounting impairment tests. Prices will no longer be based on a single-day, period-end price. Rather, they will be based on either the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements.
- Disclosure of probable and possible reserves is allowed.
- The estimation of reserves will allow the use of reliable technology that was not previously recognized by the SEC.
- Numerous changes in reserves disclosures mandated by SEC for Form 10-K.
- Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

The change in prices used to calculate reserves did not have a material impact upon our reserves estimation in the current period. These changes could have a material impact upon our financial statements in future periods due to the uncertainty of oil and gas prices.

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 damages 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, and such pricing volatility has continued through 2009 with some improvement during the last half of 2009 and into 2010.

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.

At September 30, 2010, we did not have any outstanding derivative instruments in place for future production.

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 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 subordinated 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 September 30, 2010, 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 2010 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 nine months of 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

SWIFT ENERGY COMPANY
PART II. - OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 1A. Risk Factors.

There have been no material changes in our risk factors from those disclosed in our 2009 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 third quarter of 2010:

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)
07/01/10 – 07/31/10 (1)	265	$24.99	---	$---
08/01/10 – 08/31/10 (1)	202	$28.42	---	---
09/01/10 – 09/30/10 (1)	---	$---	---	---
Total	467	$26.47	---	$---

(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.

10.01 Second Amended and Restated Credit Agreement dated September 21, 2010, among Swift Energy Company, Swift Operating, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent, BNP Paribas and Wells Fargo Bank, N.A., as Co-Syndication Agents, Bank of Scotland plc and Société Générale, as

	Co-Documentation Agents, and the lenders party thereto incorporated by reference to Exhibit 10.01 to Form 8-K filed September 27, 2010.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

SIGNATURES

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

SWIFT ENERGY COMPANY
(Registrant)

Date: November 4, 2010	By:	/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President and Chief Financial Officer
Date: November 4, 2010	By:	/s/ Barry S. Turcotte Barry S. Turcotte Vice President, Controller and Principal Accounting Officer

Exhibit Index

10.01	Second Amended and Restated Credit Agreement dated September 21, 2010, among Swift Energy Company, Swift Operating, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent, BNP Paribas and Wells Fargo Bank, N.A., as Co-Syndication Agents, Bank of Scotland plc and Société Générale, as Co-Documentation Agents, and the lenders party thereto incorporated by reference to Exhibit 10.01 to Form 8-K filed September 27, 2010.
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* Filed herewith