SWIFT ENERGY CO
Form 10-Q
August 04, 2011

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

FORM 10-Q

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

For the quarterly period ended June 30, 2011
Commission File Number 1-8754

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

Texas	20-3940661
(State of Incorporation)	(I.R.S. Employer Identification No.)

16825 Northchase Drive, Suite 400
Houston, Texas 77060
(281) 874-2700
(Address and telephone number of principal executive offices)
Securities registered pursuant to Section 12(b) of the Act:

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.
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 filer	þ	Accelerated filer	o	Non-accelerated filer	o	Smaller reporting company	o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
YesoNoþ

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

Common Stock	
($.01 Par Value)	42,468,169 Shares
(Class of Stock)	(Outstanding at July 31, 2011)

SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2011
INDEX

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

	June 30, 2011 (Unaudited)	December 31, 2010
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 32,298	$ 86,367
Accounts receivable	50,146	46,975
Deferred tax asset	3,310	6,347
Other current assets	14,842	18,105
Assets held for sale	---	564
Total Current Assets	100,596	158,358
Property and Equipment:		
Property and Equipment	4,201,003	3,951,107
Less – Accumulated depreciation, depletion, and amortization	(2,487,813)	(2,378,262)
Property and Equipment, Net	1,713,190	1,572,845
Other Long-Term Assets	12,613	12,713
Total Assets	$ 1,826,399	$ 1,743,916
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 52,212	$ 75,594
Accrued capital costs	75,563	64,879
Accrued interest	10,760	11,010
Undistributed oil and gas revenues	4,006	5,252
Total Current Liabilities	$ 142,541	$ 156,735
Long-Term Debt	471,746	471,624
Deferred Income Taxes	180,484	157,565
Asset Retirement Obligation	71,574	70,171
Other Long-Term Liabilities	9,855	7,804
Commitments and Contingencies		
Stockholders' Equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding	---	---
Common stock, $.01 par value, 150,000,000 shares authorized, 42,946,570 and 42,440,583 shares issued, and 42,465,727 and 41,999,058 shares outstanding, respectively	429	424
Additional paid-in capital	717,945	706,857
Treasury stock held, at cost, 480,843 and 441,525 shares, respectively	(12,246)	(9,778)
Retained earnings	243,861	182,652
Accumulated other comprehensive income (loss), net of income tax	210	(138)
Total Stockholders' Equity	950,199	880,017
Total Liabilities and Stockholders' Equity	$ 1,826,399	$ 1,743,916

See accompanying Notes to Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Revenues:				
Oil and gas sales	$159,213	$105,051	$303,414	$215,076
Price-risk management and other, net	(1,785)	1,849	(1,908)	1,670
Total Revenues	157,428	106,900	301,506	216,746
Costs and Expenses:				
General and administrative, net	10,866	8,037	21,309	17,288
Depreciation, depletion, and amortization	55,816	39,029	108,737	77,303
Accretion of asset retirement obligation	1,163	975	2,299	1,929
Lease operating cost	26,706	19,936	52,090	38,584
Severance and other taxes	12,383	11,641	25,696	23,213
Interest expense, net	8,622	8,214	17,010	16,540
Total Costs and Expenses	115,556	87,832	227,141	174,857
Income from Continuing Operations Before Income Taxes	41,872	19,068	74,365	41,889
Provision for Income Taxes	15,190	6,555	27,434	15,136
Income from Continuing Operations	26,682	12,513	46,931	26,753
Income (Loss) from Discontinued Operations, net of taxes	14,346	(54)	14,278	(89)
Net Income	$41,028	$12,459	$61,209	$26,664
Per Share Amounts-				
Basic: Income from Continuing Operations	$0.62	$0.32	$1.09	$0.70
Income (Loss) from Discontinued Operations, net of taxes	0.33	(0.00)	0.33	(0.00)
Net Income	$0.95	$0.32	$1.42	$0.69
Diluted: Income from Continuing Operations	$0.61	$0.32	$1.08	$0.69
Income (Loss) from Discontinued Operations, net of taxes	0.33	(0.00)	0.33	(0.00)
Net Income	$0.95	$0.32	$1.41	$0.69
Weighted Average Shares Outstanding - Basic	42,436	37,845	42,313	37,749

See accompanying Notes to Condensed Consolidated Financial statements.

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

	Common Stock (1)	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2009	$379	$551,606	$(9,221)	$136,358	$ (223)	$678,899
Stock issued for benefit plans (59,335 shares)	-	242	1,271	-	-	1,513
Stock options exercised (136,432 shares)	1	2,086	-	-	-	2,087
Public Stock offering (4,038,270 shares)	40	140,099	-	-	-	140,139
Purchase of treasury shares (70,337 shares)	-	-	(1,828)	-	-	(1,828)
Tax benefits from share-based compensation	-	28	-	-	-	28
Employee stock purchase plan (66,564 shares)	1	950	-	-	-	951
Issuance of restricted stock (312,191 shares)	3	(3)	-	-	-	-
Amortization of share-based compensation	-	11,849	-	-	-	11,849
Net Income	-	-	-	46,294	-	46,294
Other comprehensive income	-	-	-	-	85	85
Total comprehensive income						46,379
Balance, December 31, 2010	$424	$706,857	$(9,778)	$182,652	$ (138)	$880,017
Stock issued for benefit plans (37,068 shares) (2)	-	791	821	-	-	1,612
Stock options exercised (122,852 shares) (2)	1	989	-	-	-	990
Purchase of treasury shares (76,386 shares)	-	-	(3,289)	-	-	(3,289)
Tax benefits from share-based compensation (2)	-	329	-	-	-	329
Employee stock purchase plan (49,089 shares) (2)	1	999	-	-	-	1,000
Issuance of restricted stock (334,046 shares) (2)	3	(3)	-	-	-	-
Amortization of share-based compensation (2)	-	7,983	-	-	-	7,983
Net Income (2)	-	-	-	61,209	-	61,209
Other comprehensive Income (2)	-	-	-	-	348	348

Total comprehensive income (2)						61,557
Balance, June 30, 2011 (2)	$429	$717,945	$(12,246)	$243,861	$ 210	$950,199

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

See accompanying Notes to Condensed Consolidated Financial Statements.

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

(in thousands)	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Cash Flows from Operating Activities:		
Net income	$61,209	$26,664
Minus Income (plus loss) from discontinued operations, net of taxes	(14,278)	89
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation, depletion, and amortization	108,737	77,303
Accretion of asset retirement obligation	2,299	1,929
Deferred income taxes	26,077	20,502
Stock-based compensation expense	5,939	4,905
Other	(5,240)	(1,741)
Change in assets and liabilities-		
Decrease in accounts receivable	1,682	2,951
Increase (decrease) in accounts payable and accrued liabilities	983	(10,780)
Decrease in income taxes payable	(217)	(41)
Increase (decrease) in accrued interest	(250)	7,237
Cash provided by operating activities – continuing operations	186,941	129,018
Cash provided by operating activities – discontinued operations	36	4
Net Cash Provided by Operating Activities	186,977	129,022
Cash Flows from Investing Activities:		
Additions to property and equipment	(244,798)	(129,116)
Proceeds from the sale of property and equipment	51	97
Cash used in investing activities – continuing operations	(244,747)	(129,019)
Cash provided by investing activities – discontinued operations	5,000	5,000
Net Cash Used in Investing Activities	(239,747)	(124,019)
Cash Flows from Financing Activities:		
Net proceeds from issuances of common stock	1,990	1,775
Purchase of treasury shares	(3,289)	(1,763)
Cash provided by (used in) financing activities – continuing operations	(1,299)	12
Cash provided by financing activities – discontinued operations	---	---
Net Cash Provided by (Used in) Financing Activities	(1,299)	12
Net Increase (Decrease) in Cash and Cash Equivalents	(54,069)	5,015
Cash and Cash Equivalents at Beginning of Period	86,367	38,469
Cash and Cash Equivalents at End of Period	$32,298	$43,484
Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	$16,171	$8,725
Cash paid during period for income taxes	$1,620	$168

See accompanying Notes to Condensed Consolidated Financial Statements.

Notes to Condensed Consolidated Financial Statements
Swift Energy Company and Subsidiaries

(1) General Information

The condensed consolidated financial statements included herein have been prepared by Swift Energy Company ("Swift Energy," the "Company," or "we") and reflect necessary adjustments, all of which were of a recurring nature unless otherwise disclosed herein, and are in the opinion of our management necessary for a fair presentation. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission. We believe that the disclosures presented are adequate to allow the information presented not to be misleading. The condensed consolidated financial statements should be read in conjunction with the audited financial statements and the notes thereto included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010 as filed with the Securities and Exchange Commission.

(2) Summary of Significant Accounting Policies

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

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

Subsequent Events. We have evaluated subsequent events of our condensed consolidated financial statements. Other than the settlement of legal claims as described in Note 6 of the condensed consolidated financial statements, there were no material subsequent events requiring additional disclosure in these financial statements.

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

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- estimates related to the collectability of accounts receivable and the credit worthiness of our customers,
- estimates of the counterparty bank risk related to letters of credit that our customers may have issued on our behalf,
- estimates of future costs to develop and produce reserves,
- accruals related to oil and gas sales, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage, and the solvency of insurance providers,
- estimates in the calculation of share-based 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 six months ended June 30, 2011 and 2010, such internal costs capitalized totaled $14.4 million and $11.9 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the six months ended June 30, 2011 and 2010, capitalized interest on unproved properties totaled $3.7 million and $3.7 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

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

(in thousands)	June 30, 2011	December 31, 2010
Property and Equipment		
Proved oil and gas properties	$ 4,080,741	$ 3,835,173
Unproved oil and gas properties	81,303	78,429
Furniture, fixtures, and other equipment	38,959	37,505
Less – Accumulated depreciation, depletion, and amortization	(2,487,813)	(2,378,262)
Property and Equipment, Net	$ 1,713,190	$ 1,572,845

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

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

We compute the provision for depreciation, depletion, and amortization ("DD&A") of oil and natural gas properties using the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties—including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties—by an overall rate determined by dividing the physical units of oil and natural gas produced during the period by the total estimated units of proved oil and natural gas reserves at the beginning of the period. This calculation is done on a country-by-country basis, and the period over which we will amortize these properties is dependent on our production from these properties in future years. Furniture, fixtures, and other equipment are recorded at cost and are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between 2 and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

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

The cost of unproved properties not being amortized is assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized.

8

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using the preceding 12-months' average price based on closing prices on the first day of each month, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). Our hedges at June 30, 2011 and December 31, 2010 consisted of oil and natural gas price floors that did not materially affect prices used in these calculations. This calculation is done on a country-by-country basis.

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

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

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Swift Energy uses the entitlement method of accounting in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying condensed consolidated balance sheets. Natural gas balancing receivables are reported in "Other current assets" on the accompanying condensed consolidated balance sheets when our ownership share of production exceeds sales. As of June 30, 2011 and December 31, 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.

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 June 30, 2011 and December 31, 2010, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balance on the accompanying condensed consolidated balance sheets.

At June 30, 2011 our "Accounts Receivable" balance included $45.4 million for oil and gas sales, $3.4 million for joint interest owners and $1.4 million for other receivables. At December 31, 2010 our "Accounts receivable" balance included $43.3 million for oil and gas sales, $2.3 million for joint interest owners and $1.4 million for other receivables.

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

The 7-1/8% senior notes due 2017 mature on June 1, 2017, and the balance of their issuance costs at June 30, 2011, was $2.8 million, net of accumulated amortization of $1.4 million. The 8-7/8% senior notes due 2020 mature on January 15, 2020, and the balance of their issuance costs at June 30, 2011, was $4.5 million, net of accumulated amortization of $0.5 million. The issuance costs associated with our revolving credit facility, which was revised and extended in May 2011, had been capitalized and is being amortized over the life of the facility. The balance of revolving credit facility issuance costs at June 30, 2011, was $4.0 million, net of accumulated amortization of $3.6 million.

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

Price-Risk Management Activities. The Company follows FASB ASC 815-10, which requires that changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The guidance also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the condensed consolidated balance sheets as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the statement of operations and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Changes in the fair value of derivatives that do not meet the criteria for hedge accounting, and the ineffective portion of the hedge, are recognized currently in income.

We have a price-risk management policy to use derivative instruments to protect against declines in oil and natural gas prices, mainly through the purchase of price floors and collars. During the three months ended June 30, 2011 and 2010, we recognized a net loss of $0.8 million and a net gain of $1.5 million, respectively, relating to our derivative activities. During the first six months of 2011 and 2010, we recognized a net loss of $1.0 million and a net gain of $1.0 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 June 30, 2011, the Company had recorded $0.2 million, net of taxes of $0.1 million of derivative losses in "Accumulated other comprehensive loss, net of income tax" on the accompanying condensed consolidated balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for the six months ended June 30, 2011 and 2010 was not material. All amounts currently held in "Accumulated other comprehensive loss, net of income tax" will be realized within the next three months when the forecasted sale of hedged production occurs.

At June 30, 2011, we had natural gas price floors in effect for the contract months of July through August 2011 that cover natural gas production of 2,495,000 MMBtu from July through August 2011 with strike prices ranging between $4.55 and $4.75.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive loss, net of income tax." When the hedged transactions are recorded upon the actual sale of the oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive loss, net of income tax" on the accompanying condensed consolidated balance sheets and are recorded in "Price-risk management and other, net" on the accompanying condensed consolidated statements of operations. The fair values of our derivatives are computed using the Black-Scholes-Merton option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments at June 30, 2011 and December 31, 2010, was $0.2 million and $0.3 million, respectively and was recognized on the accompanying condensed consolidated balance sheets in "Other current assets." At June 30, 2011, we had $0.9 million in receivables for concluded natural gas hedges covering July 2011 production and concluded oil hedges covering June 2011 production which were recognized on the accompanying balance sheet in "Other Receivables" and were subsequently collected in July 2011.

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 for the first six months of 2011 and 2010 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate was $6.6 million and $6.0 million in the first six months of 2011 and 2010, respectively.

Inventories. Inventories consist primarily of tubulars and other equipment that we expect to place in service in production operations. Inventories carried at cost (weighted average method) are included in “Other current assets” on the accompanying condensed consolidated balance sheets totaling $8.7 million at June 30, 2011 and $12.8 million at December 31, 2010. In the second quarter of 2011, we recorded a charge of $0.9 million related to inventory obsolescence in “Price-risk management and other, net” on the accompanying condensed statement of operations.

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 June 30, 2011, we did not have any amount accrued for interest and penalties on uncertain tax positions.

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

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

(in thousands)	June 30, 2011	December 31, 2010
Trade accounts payable (1)	$ 16,038	$ 22,459
New Zealand deferred revenue	---	10,000
Accrued expenses	16,581	19,284
Asset retirement obligation – current portion	7,986	8,708
Accrued severance taxes	4,130	10,253
Other accrued liabilities	7,477	4,890
Total accounts payable and accrued liabilities	$ 52,212	$ 75,594

(1) Included in “trade accounts payable” are liabilities of approximately $11.1 million and $8.1 million at June 30, 2011 and December 31, 2010, respectively, for outstanding checks. This represents the amounts by which checks were issued, but not presented by vendors to the Company’s banks for collection, exceeded balances in the applicable disbursement bank accounts.

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

Restricted Cash. These balances primarily include amounts held in escrow accounts to satisfy domestic plugging and abandonment obligations. As of June 30, 2011 and December 31, 2010 these assets include approximately $1.3 million. These amounts are restricted as to their current use, and will be released when we have satisfied all plugging and abandonment obligations in certain fields. Restricted cash balances are reported in “Other long-term assets” on the accompanying condensed consolidated balance sheets.

Accumulated Other Comprehensive Loss, Net of Income Tax. We follow the guidance contained in FASB ASC 220-10, which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At June 30, 2011, the Company had recorded $0.2 million, net of taxes of $0.1 million, as derivative losses in “Accumulated other comprehensive income (loss), net of income tax” on the accompanying condensed consolidated balance sheet. The components of accumulated other comprehensive loss and related tax effects for 2011 were as follows (in thousands):

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2010	$ (218)	$ 81	$ (138)
Change in fair value of cash flow hedges	(333)	121	(212)
Effect of cash flow hedges settled during the period	883	(324)	559
Other comprehensive income at June 30, 2011	$ 332	$ (122)	$ 210

Total comprehensive income was $41.5 million and $11.6 million for the three months ended June 30, 2011 and 2010, respectively. Total comprehensive income was $61.6 million and $26.9 million for the six months ended June 30, 2011 and 2010, respectively.

Asset Retirement Obligation. We record these obligations in accordance with the guidance contained in FASB ASC 410-20. This guidance requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. The liability is discounted from the expected date of abandonment. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis over the estimated oil and natural gas reserves of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement which is included in the full cost balance. This guidance requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values.

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

(in thousands)	2011	2010
Asset Retirement Obligation recorded as of January 1	$ 78,879	$ 64,236
Accretion expense	2,299	1,929
Liabilities incurred for new wells and facilities construction	213	524
Reductions due to sold and abandoned wells	(258)	(75)
Revisions in estimated cash flows	(1,573)	---
Asset Retirement Obligation as of June 30	$ 79,560	$ 66,614

At June 30, 2011 and December 31, 2010, approximately $8.0 million and $8.7 million, respectively, of our asset retirement obligation are classified as a current liability in “Accounts payable and accrued liabilities” on the accompanying condensed consolidated balance sheets.

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

New Accounting Pronouncements. In June 2011, the FASB issued ASU No. 2011-05, which changes the required presentation of other comprehensive income. Under the new guidelines, entities will be required to present net income and other comprehensive income, along with the components of net income and other comprehensive income, in either one continuous statement of comprehensive income or in two separate but consecutive statements of net income and comprehensive income. The accounting standards update eliminates the option of presenting the components of other comprehensive income within the statement of changes in stockholders' equity. We will adopt this guidance for the period ending March 31, 2012, although early adoption is permitted, and do not expect the guidance to have a material impact on our financial position or results of operations.

In May 2011, the FASB issued ASU No. 2011-04 to provide additional guidance related to fair value measurements and disclosures. The guidance, which is incorporated into FASB ASC 820-10, generally provides clarifications to existing fair value measurement and disclosure requirements and also creates or modifies other fair value measurement and disclosure requirements. We will adopt this guidance, as required, for the period ending March 31, 2012 and do not expect the guidance to have a material impact on our financial position or results of operations.

(3) Share-Based Compensation

We have various types of share-based compensation plans. Refer to Note 6 of our consolidated financial statements in our Annual Report on Form 10K for the fiscal year ended December 31, 2010, for additional information related to these share-based compensation plans.

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

We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the price at which the stock is sold over the exercise price of the options. We receive an additional tax deduction when restricted stock vests at a higher value than the value used to recognize compensation expense at the date of grant. In accordance with guidance contained in FASB ASC 718, we are required to report excess tax benefits from the award of equity instruments as financing cash flows. For the six months ended June 30, 2011 and 2010, we did not recognize any excess tax benefit or shortfall.

Net cash proceeds from the exercise of stock options were $1.0 million and $0.8 million for the six months ended June 30, 2011 and 2010, respectively. The actual income tax benefit from stock option exercises was $1.1 million and $0.2 million for the six months ended June 30, 2011 and 2010, respectively.

Share-based compensation expense for both stock options and restricted stock issued to both employees and non-employees, which was recorded in “General and administrative, net” in the accompanying condensed consolidated statements of operations, was $3.1 million and $2.3 million for the three months ended June 30, 2011 and 2010, respectively, and was $5.6 million and $4.4 million for the six month periods ended June 30, 2011 and 2010. Share-based compensation recorded in lease operating cost was $0.1 million for the three months ended June 30, 2011 and 2010, and was $0.2 million for the six month periods ended June 30, 2011 and 2010. We also capitalized $1.0 million and $0.4 million of share-based compensation for the three months ended June 30, 2011 and 2010, respectively, and capitalized $2.0 million and $0.8 million for the six month periods ended June 30, 2011 and 2010. We view all awards of share-based 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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Dividend yield	0 %	0 %	0 %	0 %
Expected volatility	58.6 %	68.4 %	58.8 %	63.0 %
Risk-free interest rate	0.5 %	0.6 %	1.9 %	2.1 %
Expected life of options (in years)	2.0	2.0	3.8	4.3
	$12.24	$11.12	$19.17	$12.60

Weighted-average
grant-date fair
value

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

At June 30, 2011, we had $5.1 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 six months ended June 30, 2011:

	Shares	Wtd. Avg. Exercise Price
Options outstanding, beginning of period	1,361,779	$ 29.67
Options granted	307,394	$ 42.56
Options canceled	(67,529)	$ 55.19
Options exercised	(218,313)	$ 22.71
Options outstanding, end of period	1,383,331	$ 32.39
Options exercisable, end of period	736,950	$ 30.87

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at June 30, 2011 was $11.3 million and 6.2 years and $7.2 million and 4.7 years, respectively. The total intrinsic value of options exercised during the six months ended June 30, 2011 was $4.1 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, 2010, allow for the issuance of restricted stock awards that may not be sold or otherwise transferred until certain restrictions have lapsed. The unrecognized compensation cost related to these awards is expected to be expensed over the period the restrictions lapse (generally one to three years).

The compensation expense for these awards was determined based on the closing market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of June 30, 2011, we had unrecognized compensation expense of $19.8 million related to restricted stock awards which is expected to be recognized over a weighted-average period of 1.4 years. The grant date fair value of shares vested during the six months ended June 30, 2011 was $8.1 million.

The following table represents restricted stock activity for the six months ended June 30, 2011:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	734,286	$ 22.87
Restricted shares granted	416,800	$ 42.29
Restricted shares canceled	(26,558)	$ 30.85
Restricted shares vested	(334,046)	$ 24.69
Restricted shares outstanding, end of period	790,482	$ 32.13

(4) Earnings Per Share

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

Basic earnings per share ("Basic EPS") has been computed using the weighted average number of common shares outstanding during each period. Diluted EPS for the three and six month periods ended June 30, 2011 and 2010 assumes, as of the beginning of the period, exercise of stock options using the treasury stock method. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the three and six month periods ended June 30, 2011 and 2010, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the three and six month periods ended June 30, 2011 and 2010 (in thousands, except per share amounts):

	Three Months Ended June 30, 2011			Three Months Ended June 30, 2010		
	Income from Continuing Operations	Shares	Per Share Amount	Income from Continuing Operations	Shares	Per Share Amount
Basic EPS:						
Income from continuing operations, and Share Amounts	$26,682	42,436		$12,513	37,845	
Less: Income from continuing operations allocated to unvested shareholders	(456)	---		(242)	---	
Income from continuing operations allocated to common shares	$26,226	42,436	$0.62	$12,271	37,845	$0.32
Dilutive Securities:						
Plus: Income from continuing operations allocated to unvested shareholders	456	---		242	---	
Less: Income from continuing operations re-allocated to unvested shareholders	(454)	---		(241)	---	
Stock Options	---	229		---	258	
Diluted EPS:						
Income from continuing operations allocated to common shares, and assumed share conversions	$26,228	42,665	$0.61	$12,272	38,103	$0.32

	Six Months Ended June 30, 2011			Six Months Ended June 30, 2010		
	Income from Continuing Operations	Shares	Per Share Amount	Income from Continuing Operations	Shares	Per Share Amount
Basic EPS:						
Income from continuing operations, and Share Amounts	$46,931	42,313		$26,753	37,749	
Less: Income from continuing operations allocated to unvested shareholders	(807)	---		(512)	---	
Income from continuing operations allocated to common shares	$46,124	42,313	$1.09	$26,241	37,749	$0.70
Dilutive Securities:						

Plus: Income from continuing operations allocated to unvested shareholders	807	---		512	---	
Less: Income from continuing operations re-allocated to unvested shareholders	(803)	---		(509)	---	
Stock Options	---	219		---	230	
Diluted EPS:						
Income from continuing operations allocated to common shares, and assumed share conversions	$46,128	42,532	$1.08	$26,244	37,979	$0.69

Options to purchase approximately 1.4 million shares at an average exercise price of $32.39 were outstanding at June 30, 2011, while options to purchase approximately 1.5 million shares at an average exercise price of $29.18 were outstanding at June 30, 2010. Approximately 0.6 million and 1.2 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months ended June 30, 2011 and 2010, respectively, and 0.8 million and 1.2 million stock options to purchase shares were not included in the computation of Diluted EPS for the six months ended June 30, 2011, because these stock options were antidilutive, in that the sum of the stock option price, unrecognized compensation expense and excess tax benefits recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during those periods.

(5) Long-Term Debt

Our long-term debt as of June 30, 2011 and December 31, 2010, was as follows (in thousands):

	June 30, 2011	December 31, 2010
Bank Borrowings	$ ---	$ ---
7-1/8% senior notes due 2017	250,000	250,000
8-7/8% senior notes due 2020	221,746	221,624
Long-Term Debt	$ 471,746	$ 471,624

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

We have capitalized interest on our unproved properties in the amount of $1.9 million and $1.9 million for the three months ended June 30, 2011 and 2010, respectively and we have capitalized interest on our unproved properties in the amount of $3.7 million and $3.7 million for the six months ended June 30, 2011 and 2010, respectively.

Bank Borrowings. In May 2011 we renewed and extended our $500.0 million credit facility with a syndicate of ten banks through May 12, 2016, 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 and subject to the terms of the credit agreement. We also increased our borrowing base to $400.0 million from $300.0 million, while the commitment amount remains at $300.0 million. Debt issuance costs of approximately $0.7 million related to this extension of the credit facility were capitalized and are being amortized over the life of the facility.

At June 30, 2011 and December 31, 2010 we had no borrowings under our credit facility. The interest rate on our credit facility is either (a) the lead bank's prime plus an applicable margin or (b) Eurodollar rate 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 50 to 150 basis points above the Alternative Base Rate and escalating rates of 150 to 250 basis points for Eurodollar rate loans. The commitment fee associated with the unfunded portion of the borrowing base is set at 50 basis points. At June 30, 2011, the lead bank's prime rate was 3.25%.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $15.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $50.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX) and limitations on incurring other debt. Since inception, no cash dividends have been declared on our common stock. We are currently in compliance with the provisions of this agreement. The credit facility is secured by our domestic oil and natural gas properties. Under the terms of the credit facility, we can increase the commitment amount to the total amount of the borrowing base with unanimous consent of the bank group as it might change from time to time. In conjunction with our regularly scheduled borrowing base redetermination, which occurs every six months, we expect the borrowing base amount to remain at or above the current level.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $0.6 million and $0.4 million for the three months ended June 30, 2011 and 2010, respectively, and $1.2 million and $0.9 million for the six months ended June 30, 2011 and 2010, respectively. The amount of commitment fees included in interest expense, net was $0.4 million and $0.3 million for the three month periods ended June 30, 2011 and 2010, respectively, and $0.7 million and $0.7 million for the six months ended June 30, 2011 and 2010, respectively.

Senior Notes Due 2020. These notes consist of $225 million of 8-7/8% senior notes issued at 98.389% of par, which equates to an effective yield to maturity of 9-1/8%. The notes were issued on November 25, 2009 with an original discount of $3.6 million and will mature on January 15, 2020. The original discount of $3.6 million is recorded in "Long-Term Debt" on our condensed consolidated balance sheets and will be amortized over the life of the notes. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on January 15 and July 15 and commenced on November 25, 2009. On or after January 15, 2015, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.438% of principal, declining in twelve-month intervals to 100% in 2018 and thereafter. In addition, prior to January 15, 2013, we may redeem up to 35% of the principal amount of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 108.875% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $5.0 million of debt issuance costs related to these notes, which is included in "Other Long–Term Assets" on the accompanying condensed consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 8-7/8% senior notes due 2020, including amortization of debt issuance costs and debt discount, totaled $5.1 million for each of the three months ended June 30, 2011 and 2010, respectively, and $10.3 million for the six months ended June 30, 2011 and 2010, respectively.

Senior Notes Due 2017. These notes consist of $250.0 million of 7-1/8% senior notes due 2017, which were issued on June 1, 2007 at 100% of the principal amount and will mature on June 1, 2017. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on June 1 and December 1, and commenced on December 1, 2007. On or after June 1, 2012, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.563% of principal, declining in twelve-month intervals to 100% in 2015 and thereafter. We incurred approximately $4.2 million of debt issuance costs related to these notes, which is included in “Other Long-Term Assets” on the accompanying condensed consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 7-1/8% senior notes due 2017, including amortization of debt issuance costs, totaled $4.5 million for the three months ended June 30, 2011 and 2010, respectively, and $9.1 million for the six months ended June 30, 2011 and 2010, respectively.

(6) Discontinued Operations

In August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments to be received nine months after the sale, 18 months after the sale, and 30 months after the sale. The Company initially deferred the gain on the sale due to legal claims around the transfer of this property. In July 2011, a settlement was reached and all legal claims were dismissed. As a result, in the second quarter of 2011 the Company recognized sale proceeds of $15.0 million, net of $0.6 million in capitalized costs in assets held for sale, relating to our remaining New Zealand permit. In accordance with guidance contained in FASB ASC 360-10, the results of operations for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. As of June 30, 2011 all payments under this sale agreement had been received. There is essentially no income tax expense on this gain as the Company has offsetting New Zealand tax losses that were previously unrecognized due to a valuation allowance.

Our income from discontinued operations was $14.3 million for the three and six months ended June 30, 2011, which equated to $0.33 per basic and diluted share for the periods. Our loss from discontinued operations, net of taxes was less than $0.1 million for the three and six months ended June 30, 2010, which equated to $0.00 per basic and diluted share for the periods. Our cash provided by operating activities – discontinued operations was less than $0.1 million for the three and six months ended June 30, 2011, and June 30, 2010.

(7) Acquisitions and Dispositions

There were no material acquisitions or dispositions in 2010 or the six months ended June 30, 2011.

(8) Fair Value Measurements

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

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair value of the bank borrowings approximate the carrying amounts as of June 30, 2011 and December 31, 2010, and was determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of June 30, 2011 and December 31, 2010, the fair value of our senior notes due 2017, was $248.9 million, or 99.6% of face value, and $254.7 million, or 101.9% of face value, respectively. Based upon quoted market prices as of June 30, 2011 and December 31, 2010, the fair value of our senior notes due 2020, which were issued in November 2009, were $247.5 million, or 110.0% of face value and $242.3 million, or 107.7% of face value, respectively. The carrying value of our senior notes due 2017 was $250.0 million at June 30, 2011 and December 31, 2010, while the carrying value of our senior notes due 2020 was $221.7 million and $221.6 million at June 30, 2011 and December 31, 2010, respectively.

The following table presents our assets that are measured at fair value as of June 30, 2011 and are categorized using the fair value hierarchy. The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (in millions):

		Fair Value Measurements at June 30, 2011		
Assets	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Money Market Funds	$ 26.0	$ 26.0	$ ---	$ ---
Natural Gas Derivatives	$ 0.2	$ ---	$ 0.2	$ ---
Oil Derivatives	$ ---	$ ---	$ ---	$ ---

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

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

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

(9) Condensed Consolidating Financial Information

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

Condensed Consolidating Balance Sheets

(in thousands)	June 30, 2011				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
ASSETS					
Current assets	$---	$100,538	$58	$---	$ 100,596
Property and equipment	---	1,713,190	---	---	1,713,190
Investment in subsidiaries (equity method)	950,199	---	864,684	(1,814,883)	---
Other assets	---	12,613	85,489	(85,489)	12,613
Total assets	$950,199	$1,826,341	$950,231	$(1,900,372)	$ 1,826,399
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$---	$142,509	$32	$---	$ 142,541
Long-term liabilities	---	819,148	---	(85,489)	733,659
Stockholders' equity	950,199	864,684	950,199	(1,814,883)	950,199
Total liabilities and stockholders' equity	$950,199	$1,826,341	$950,231	$(1,900,372)	$ 1,826,399

(in thousands)	December 31, 2010				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
ASSETS					
Current assets	$---	$158,335	$23	$---	$ 158,358
Property and equipment	---	1,572,845	---	---	1,572,845
Investment in subsidiaries (equity method)	880,017	---	808,780	(1,688,797)	---
Other assets	---	12,713	81,221	(81,221)	12,713
Total assets	$880,017	$1,743,893	$890,024	$(1,770,018)	$ 1,743,916
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$---	$146,728	$10,007	$---	$ 156,735
Long-term liabilities	---	788,385	---	(81,221)	707,164
Stockholders' equity	880,017	808,780	880,017	(1,688,797)	880,017
Total liabilities and stockholders' equity	$880,017	$1,743,893	$890,024	$(1,770,018)	$ 1,743,916

Condensed Consolidating Statements of Income

(in thousands)	Three Months Ended June 30, 2011				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Revenues	$---	$157,428	$---	$ ---	$ 157,428
Expenses	---	115,556	---	---	115,556
Income before the following:	---	41,872	---	---	41,872
Equity in net earnings of subsidiaries	41,028	---	26,682	(67,710)	---
Income from continuing operations, before income taxes	41,028	41,872	26,682	(67,710)	41,872
Income tax provision	---	15,190	---	---	15,190
Income from continuing operations	41,028	26,682	26,682	(67,710)	26,682
Income from discontinued operations, net of taxes	---	---	14,346	---	14,346
Net income	$41,028	$26,682	$41,028	$ (67,710)	$ 41,028

(in thousands)	Six Months Ended June 30, 2011				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Revenues	$---	$301,506	$---	$ ---	$ 301,506
Expenses	---	227,141	---	---	227,141
Income before the following:	---	74,365	---	---	74,365
Equity in net earnings of subsidiaries	61,209	---	46,931	(108,140)	---
Income from continuing operations, before income taxes	61,209	74,365	46,931	(108,140)	74,365
Income tax provision	---	27,434	---	---	27,434
Income from continuing operations	61,209	46,931	46,931	(108,140)	46,931
Income from discontinued operations, net of taxes	---	---	14,278	---	14,278

Net income	$61,209	$46,931	$61,209	$(108,140)	$61,209

(in thousands)	Three Months Ended June 30, 2010				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Revenues	$---	$106,900	$---	$ ---	$ 106,900
Expenses	---	87,832	---	---	87,832
Income before the following:	---	19,068	---	---	19,068
Equity in net earnings of subsidiaries	12,459	---	12,513	(24,972)	---
Income from continuing operations, before income taxes	12,459	19,068	12,513	(24,972)	19,068
Income tax provision	---	6,555	---	---	6,555
Income from continuing operations	12,459	12,513	12,513	(24,972)	12,513
Loss from discontinued operations, net of taxes	---	---	(54)	---	(54)
Net income	$12,459	$12,513	$12,459	$ (24,972)	$ 12,459

(in thousands)	Six months Ended June 30, 2010				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Revenues	$---	$216,746	$---	$ ---	$ 216,746
Expenses	---	174,857	---	---	174,857
Income before the following:	---	41,889	---	---	41,889
Equity in net earnings of subsidiaries	26,664	---	26,753	(53,417)	---
Income from continuing operations, before income taxes	26,664	41,889	26,753	(53,417)	41,889
Income tax provision	---	15,136	---	---	15,136
Income from continuing operations	26,664	26,753	26,753	(53,417)	26,753
Loss from discontinued operations, net of taxes	---	---	(89)	---	(89)

Net income	$26,664	$26,753	$26,664	$(53,417)	$26,664

21

Condensed Consolidating Statements of Cash Flows

(in thousands)	Six Months Ended June 30, 2011				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Cash flow from operations	$---	$186,941	$36	$ ---	$ 186,977
Cash flow from investing activities	---	(239,747)	5,000	(5,000)	(239,747)
Cash flow from financing activities	---	(1,299)	(5,000)	5,000	(1,299)
Net increase (decrease) in cash	---	(54,105)	36	---	(54,069)
Cash, beginning of period	---	86,346	21	---	86,367
Cash, end of period	$---	$32,241	$57	$ ---	$ 32,298

(in thousands)	Six Months Ended June 30, 2010				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Cash flow from operations	$---	$129,018	$4	$ ---	$ 129,022
Cash flow from investing activities	---	(124,019)	5,000	(5,000)	(124,019)
Cash flow from financing activities	---	12	(5,000)	5,000	12
Net increase in cash	---	5,011	4	---	5,015
Cash, beginning of period	---	33,405	5,064	---	38,469
Cash, end of period	$---	$38,416	$5,068	$ ---	$ 43,484

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

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

Overview

We are an independent oil and natural gas company formed in 1979, and we are engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from our Texas properties as well as onshore and inland waters of Louisiana. We are one of the largest producers of crude oil in the state of Louisiana, and hold a large acreage position in Texas prospective for liquids-rich Eagle Ford shale and Olmos tight sands development. Oil production accounted for 38% of our second quarter of 2011 production and 70% of our oil and gas revenues, and combined production for both oil and natural gas liquids ("NGLs") made up 50% of our second quarter of 2011 production and 81% of our oil and gas sales. This emphasis has allowed us to benefit from better margins for oil production than natural gas production during the quarter.

Second Quarter 2011 Highlights

Increases in Earnings and Production. Our income increased by $14.2 million and our production volumes increased by 30% in the second quarter of 2011 when compared to the same period in 2010. Natural gas and NGL production volumes increased 70% and 20% in the second quarter of 2011, respectively, due to our recent South Texas activities, while oil volumes increased 2% from second quarter of 2010 levels. Sequentially, production decreased slightly from production levels in the first quarter of 2011, as natural gas production in McMullen County, Texas was periodically curtailed throughout the quarter due to maintenance projects by a large pipeline operator, and completely shut-in by that operator for four days at the end of June. We expect a new pipeline being built by a new midstream provider to be completed by the end of the third quarter, and we have entered into a long-term processing and transportation agreement under which firm capacity will be available to us of up to 90 million cubic feet of gas per day. Prices received for oil and NGLs in the second quarter of 2011 were 44% and 20% higher, respectively, than average prices we received in the second quarter of 2010, while natural gas prices increased 6%.

Liquidity at Quarter-End. We ended the second quarter of 2011 with $32.3 million of cash and cash equivalents on our balance sheet. Taken together with our available borrowing capacity under our credit agreement at June 30, 2011, our liquidity provides capital, if needed, for our 2011 drilling program.

Second Quarter 2011 Drilling and Operational Activities. In our South Texas core region, one operated and two non-operated, horizontal, development wells were drilled to the Eagle Ford shale. Six operated horizontal development wells were drilled in the Olmos formation. As of June 30, 2011, a total of seven horizontal wells were awaiting completion activities. At the end of 2010, our South Texas core region surpassed Southeast Louisiana in terms of both production and proven reserves. We had also entered into a long-term agreement with a major industry service provider for South Texas, securing access to hydraulic fracturing services at competitive prices for a two-year period with approximately one year still remaining on the contract.

In our Southeast Louisiana core region, we completed one development well and one extension well in the Lake Washington field, the development well was spud in late first quarter 2011. The initial rate of the first test well was approximately 2,500 Boe per day, while the most recent test rate of the first well was approximately 1,200 Boe per day. The initial production rate of the most recent well was approximately 400 Boe per day. These first well encountered approximately 93 feet and the second well encountered approximately 150 feet of true vertical net pay. These wells will yield between 7 to 11 prospects in the future. Recompletion and production optimization work continued during the quarter at the Lake Washington field with 4 recompletions, 7 gas lift modifications, 6 wells returned to production, and 9 sliding sleeves performed in the second quarter. The average initial production response from all of these operations combined was approximately 2,500 Boe per day. With two new wells being brought online during the quarter and these low cost operations helping to manage natural production declines, the Lake Washington field production only declined 4% from the first quarter 2011 levels. We will continue to focus on relatively low risk, low cost oil activity and also plan to re-commence drilling in the Lake Washington field in the fourth quarter of 2011 and into 2012

In our Central Louisiana/East Texas core region, we participated in a non-operated well and an operated well in our Burr Ferry field during the second quarter. These wells should be completed in the third quarter of 2011. In the fourth quarter of 2011, we expect to spud an operated well in our Masters Creek field and participate in several non-operated wells in the Burr Ferry field.

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

During the third quarter in our Burr Ferry field, we and our partner expanded our original joint operating area; and have also entered into another agreement to jointly develop acreage in a newly identified second operating area adjacent to the first operating area. There are now approximately 73,000 gross acres leased in the first joint operating area in which we hold a 50% working interest. We also own approximately 39,000 fee mineral acres in the area. In the second joint operating area, there are now approximately 32,000 gross acres leased in which we hold a 45% working interest. Our position in both areas is non-operated and additional leasing is expected to continue in both areas.

Potential Dispositions. We recently engaged a firm to facilitate the sale of certain non-strategic properties located in Louisiana, Texas and Alabama. The fields in Louisiana include Horseshoe Bayou/Bayou Sale, High Island, Bayou Penchant, Jeanerette and Cote Blanche Island. The Texas fields include Bego South and Briscoe Ranch. The Alabama field includes Chunchula.

Discontinued Operations. In August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments to be received nine months after the sale, 18 months after the sale, and 30 months after the sale. The Company initially deferred the gain on the sale due to legal claims around the transfer of this property. In July 2011, a settlement was reached and all legal claims were dismissed. As a result in the second quarter of 2011, the Company recognized sale proceeds of $15.0 million, net of $0.6 million in capitalized costs in assets held for sale, relating to our remaining New Zealand permit. In accordance with guidance contained in FASB ASC 360-10, the results of operations for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. As of June 30, 2011 all payments under this sale agreement had been received. There is essentially no income tax expense on this gain as the Company has offsetting New Zealand tax losses that were previously unrecognized due to a valuation allowance.

2011 Objectives

In 2011, we are focused on accelerating our pace of development in South Texas, improving our results through more efficient execution and exploiting other areas of our asset base. Our exposure to liquids rich production growth in South Texas, our oil production in South Louisiana, our growing leasehold acreage in the Austin Chalk and our deep exploration prospect inventory along the Gulf Coast together provide a uniquely positioned resource portfolio. For 2011, we are targeting an increase in production volumes of 28% to 34% over 2010 levels and reserves growth of 15% to 20% over 2010 levels.

Results of Operations

Summary Prior Quarter Comparison

In the Second quarter of 2011 we had revenues of $157.4 million, an increase of 9% compared to first quarter 2011 levels. Our weighted average sales price received increased 11% to $60.29 per Boe from $54.51 per Boe, while our production volumes were flat. This $13.4 million increase in revenues from first quarter 2011 levels was mainly due to a 14% increase in oil prices.

Our overall costs and expenses increased in the second quarter of 2011 by $4.0 million when compared to first quarter 2011 levels, and were higher on a Boe basis, as production volumes were flat. Depreciation, depletion and amortization expense increased 5%, mainly due to a higher depletable property base. Lease operating costs increased by 5% due to increased salt water handling and other costs in our South Texas core region. Severance and other taxes decreased 7% due to production in our South Texas and Burr Ferry fields that qualify for reduced severance tax rates.

Net income from continuing operations for the second quarter of 2011 was $26.7 million compared to $20.2 million in the first quarter of 2011.

Core Regions

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

- South Texas

- Olmos

AWP
Sun TSH
Las Tiendas

- Eagle Ford

Hawkville AWP
Hawkville Artesia Wells
Hawkville Fasken

- Southeast Louisiana

Lake Washington
Bay de Chene

- Central and South Louisiana / East Texas

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

Revenues and Expenses — Three Months Ended June 30, 2011 and 2010

Revenues. The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the three months ended June 30, 2011 and 2010:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2011	2010	2011	2010
S. E. Louisiana	$ 77.7	$ 61.8	821	944
South Texas	54.7	25.8	1,372	732
Central and South Louisiana / E. Texas	26.1	16.8	435	338
Other	0.7	0.7	13	14
Total	$ 159.2	$ 105.1	2,641	2,028

2011 Second Quarter Revenues Breakdown. Oil and gas sales for the second quarter of 2011 increased by 52%, or $54.2 million, from the level of those revenues for the comparable 2010 period, and our net production volumes in the second quarter of 2011 increased by 30%, or 0.6 MMBoe, from net production volumes in the second quarter of 2010. Average prices for oil increased to $112.09 per Bbl in the second quarter of 2011 from $77.83 per Bbl in the second quarter of 2010. Average natural gas prices increased to $3.93 per Mcf in the second quarter of 2011 from $3.72 per Mcf in the second quarter of 2010. Average NGL prices increased to $50.41 per Bbl in the second quarter of 2011 from $41.92 per Bbl in the second quarter of 2010.

In the second quarter of 2011, our $54.2 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $38.6 million favorable impact on sales, of which $34.0 million was attributable to the 44% increase in average oil prices received, $2.9 million was attributable to the 20% increase in NGL prices, and $1.7 million was attributable to the 6% increase in natural gas prices; and
- Volume increases that had a $15.6 million favorable impact on sales, with a $1.1 million increase attributable to the less than 0.1 million Bbl increase in oil production volumes, a $2.4 million increase due to the less than 0.1 million Bbl increase in NGL production volumes, and a $12.1 million increase due to the 3.2 Bcf increase in natural gas production volumes.

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

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Three Months Ended June 30, 2011	994	335	7.9	2,641	$112.09	$50.41	$3.93
Three Months Ended June 30, 2010	979	279	4.6	2,028	$77.83	$41.92	$3.72

During the second quarter of 2011, we recorded a net loss of $0.8 million related to our derivative activities, while during the second quarter of 2010 we recorded a net gain of $1.5 million from these activities. This activity is recorded in "Price-risk management and other, net" on the accompanying condensed statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been $111.82 and $78.10 for the second quarters of 2011 and 2010, respectively, and our average natural gas price would have been $3.86 and $3.99 for the second quarters of 2011 and 2010, respectively.

Expenses. Our expenses in the second quarter of 2011 increased $27.7 million, or 32%, compared to the second quarter of 2010 for the reasons noted below.

Lease Operating Expenses ("LOE"). These expenses increased $6.8 million, or 34%, compared to the level of such expenses in the second quarter of 2010. Lease operating costs increased during 2011 due to higher product transportation costs, higher salt water disposal costs, as well as other various cost increases from our South Texas core region. Our lease operating costs per Boe produced were $10.11 and $9.83 for the second quarters of 2011 and 2010, respectively.

Depreciation, Depletion and Amortization ("DD&A"). These expenses increased $16.8 million, or 43% from the second quarter of 2010. The increase was due to a higher depletable base and higher production volumes, partially offset by higher reserves volumes. Our DD&A rate per Boe of production was $21.14 and $19.24 in the second quarters of 2011 and 2010, respectively, resulting from increases in per unit cost of reserves additions in 2011 and 2010.

General and Administrative Expenses, Net. These expenses increased $2.8 million, or 35%, from the level of such expenses in the second quarter of 2010. The increase was primarily due to higher stock and deferred compensation amounts and higher salaries and burdens in the second quarter of 2011, partially offset by higher capitalized amounts. For the second quarters of 2011 and 2010, our capitalized general and administrative costs totaled $7.1 million and $5.9 million, respectively. Our net general and administrative expenses per Boe produced increased to $4.11 per Boe in the second quarter of 2011 from $3.96 per Boe in the second quarter of 2010. The portion of supervision fees recorded as a reduction to general and administrative expenses were $3.1 million and $3.0 million for the second quarters of 2011 and 2010, respectively.

Severance and other taxes. These expenses increased $0.7 million, or 6%, from the second quarter of 2010. Severance and other taxes, as a percentage of oil and gas sales, were approximately 7.8% and 11.1% in the second quarters of 2011 and 2010, respectively. The decrease was due primarily to 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 completion.

Interest. Our gross interest cost in the second quarter of 2011 was $10.5 million, of which $1.9 million was capitalized. Our gross interest cost in the second quarter of 2010 was $10.1 million, of which $1.9 million was capitalized.

Income Taxes. Our effective income tax rate was 36.3% and 34.4% for the second quarters of 2011 and 2010, respectively. Our U.S. Federal income tax returns for 2002 forward, our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2004, and our Texas franchise tax returns after 2006 remain subject to examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

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

Net Income. Our second quarter 2011 net income of $41.0 million, including $14.3 million from discontinued operations, increased as compared to our second quarter 2010 net income of $12.5 million.

Revenues and Expenses — Six Months Ended June 30, 2011 and 2010

Revenues. The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the six months ended June 30, 2011 and 2010:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2011	2010	2011	2010
S. E. Louisiana	$ 148.8	$ 123.2	1,690	1,880
South Texas	104.3	57.3	2,733	1,522
Central and South Louisiana / E. Texas	49.1	33.1	837	641
Other	1.2	1.5	26	30
Total	$ 303.4	$ 215.1	5,286	4,073

2011 First six months Revenues Breakdown. Oil and gas sales for the first six months of 2011 increased by 41%, or $88.3 million, from the level of those revenues for the comparable 2010 period, and our net production volumes in the first six months of 2011 increased by 30%, or 1.2 MMBoe, from net production volumes in the first six months of 2010. Average prices for oil increased to $105.38 per Bbl in the first six months of 2011 from $77.96 per Bbl in the first six months of 2010. Average natural gas prices decreased to $3.87 per Mcf in the first six months of 2011 from $4.24 per Mcf in the first six months of 2010. Average NGL prices increased to $49.63 per Bbl in the first six months of 2011 from $43.37 per Bbl in the first six months of 2010.

In the first six months of 2011, our $88.3 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $52.8 million favorable impact on sales, of which $54.2 million was attributable to the 35% increase in average oil prices received, $4.3 million was attributable to the 14% increase in NGL prices, and a reduction of ($5.7) million was attributable to the 9% decrease in natural gas prices; and
- Volume increases that had a $35.5 million favorable impact on sales, with a $4.2 million increase attributable to the less than 0.1 million Bbl increase in oil production volumes, a $4.4 million increase due to the 0.1 million Bbl increase in NGL production volumes, and a $26.9 million increase due to the 6.3 Bcf increase in natural gas production volumes.

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

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

Six Months Ended June 30, 2011	1,979	683	15.7	5,286	$105.38	$49.63	$3.87
Six Months Ended June 30, 2010	1,924	582	9.4	4,073	$77.96	$43.37	$4.24

During the first six months of 2011, we recorded a net loss of $1.0 million related to our derivative activities, while during the first six months of 2010 we recorded a net gain of $1.0 million from these activities. This activity is recorded in "Price-risk management and other, net" on the accompanying condensed statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been $105.09 and $78.09 for the first six months of 2011 and 2010, respectively, and our average natural gas price would have been $3.84 and $4.32 for the first six months of 2011 and 2010, respectively.

Expenses. Our expenses in the first six months of 2011 increased $52.3 million, or 30%, compared to the first six months of 2010 for the reasons noted below.

Lease Operating Expenses ("LOE"). These expenses increased $13.5 million, or 35%, compared to the level of such expenses in the first six months of 2010. Lease operating costs increased during the first six months of 2011 due to higher product transportation costs, higher salt water disposal costs, higher repair and maintenance costs, higher equipment and compressor rental costs, as well as other various cost increases from our South Texas core region. Our lease operating costs per Boe produced were $9.85 and $9.47 for the first six months of 2011 and 2010, respectively.

Depreciation, Depletion and Amortization ("DD&A"). These expenses increased $31.4 million, or 41% from the first six months of 2010. The increase was due to a higher depletable base and higher production volumes, partially offset by higher reserves volumes. Our DD&A rate per Boe of production was $20.57 and $18.98 in the first six months of 2011 and 2010, respectively, resulting from increases in per unit cost of reserves additions in 2011 and 2010.

General and Administrative Expenses, Net. These expenses increased $4.0 million, or 23%, from the level of such expenses in the first six months of 2010. The increase was primarily due to higher stock and deferred compensation amounts in the first six months of 2011, partially offset by higher capitalized amounts. For the first six months of 2011 and 2010, our capitalized general and administrative costs totaled $14.4 million and $11.9 million, respectively. Our net general and administrative expenses per Boe produced decreased to $4.03 per Boe in the first six months of 2011 from $4.24 per Boe in the first six months of 2010. The portion of supervision fees recorded as a reduction to general and administrative expenses were $6.6 million and $6.0 million for the first six months of 2011 and 2010, respectively

Severance and other taxes. These expenses increased $2.5 million, or 11%, from the first six months of 2010. The increases were due primarily to higher revenues from higher natural gas production and higher oil prices. Severance and other taxes, as a percentage of oil and gas sales, were approximately 8.5% and 10.8% for the first six months of 2011 and 2010, respectively. The decrease in 2011 was primarily driven by a shift in product and regional mix as well as reduced tax rates for tight sand gas production related to South Texas Olmos and Eagle Ford completions.

Interest. Our gross interest cost in the first six months of 2011 was $20.8 million, of which $3.7 million was capitalized. Our gross interest cost in the first six months of 2010 was $20.2 million, of which $3.7 million was capitalized.

Income Taxes. Our effective income tax rate was 36.9% and 36.1% for the first six months of 2011 and 2010, respectively. Our U.S. Federal income tax returns for 2002 forward, our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2004, and our Texas franchise tax returns after 2006 remain subject to examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

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

Net Income. Our net income for the first six months 2011 was $61.2 million, including $14.3 million from discontinued operations, which increased compared to our net income for the first six months of 2010 which was $26.7 million.

Known Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and this volatility is expected to continue in future periods. Factors such as domestic and worldwide economic conditions and credit availability, worldwide supply disruptions, weather conditions, fluctuating currency exchange rates, and political conditions in major oil producing regions, especially the Middle East, can cause fluctuations in the price of oil. Domestic natural gas prices have shown slight improvement through 2010 and into 2011; however they remain significantly below prices in 2008. North American weather conditions, the industrial and consumer demand for natural gas, economic conditions and credit availability, storage levels of natural gas, the level of liquefied natural gas imports, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas.

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

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

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

Liquidity and Capital Resources

Capital Expenditures

2011 Capital Expenditures Incurred. Our capital expenditures were $244.8 million in the first six months of 2011 compared to $129.1 million spent in the same period of 2010. The increase of $115.7 million was mainly due to additional drilling and completion activity in our South Texas core region. These 2011 expenditures were primarily funded by $186.9 million of cash provided by operating activities and remaining cash proceeds from our stock offering in November 2010.

2011 Capital Expenditures Planned. We currently plan to finance our 2011 accrual based capital expenditures with our 2011 cash flow, cash on hand and potential line of credit borrowings. Our 2011 capital expenditures are currently budgeted at $430 million to $480 million, net of potential dispositions of non-strategic properties estimated at $30 million to $40 million. Approximately 80% of our capital budget is targeted for our South Texas core region. The Company may enter into joint venture arrangements, pooling agreements for particular prospects, and consider non-strategic property dispositions, in each case to accelerate drilling and development of its assets and diversify its risk profile. For 2011, we are targeting an increase in production volumes of 28% to 34% over 2010 levels and reserves growth of 15% to 20% over 2010 levels.

Sources of Funds

Net Cash Provided by Operating Activities. For the first six months of 2011, our net cash provided by operating activities was $186.9 million, representing a 45% increase as compared to $129.0 million generated during the same period of 2010. The $57.9 million change was primarily due to higher oil prices along with a significant increase in natural gas production during the first six months of 2011.

Existing Credit Facility. In May 2011 we renewed and extended our $500.0 million credit facility with a syndicate of ten banks through May 12, 2016, and have included a feature that allows the Company to increase the size of the aggregate facility to up to $700.0 million with additional commitments from the lenders and their consent, subject to the terms of the credit agreement. We also increased our borrowing base to $400.0 million from $300.0 million, while the commitment amount remains at $300.0 million, the limit on our borrowings without lender consent. Under the terms of the credit facility, we can increase the commitment amount to the total amount of the borrowing base with unanimous consent of the bank group as it might change from time to time. We had no amounts drawn under our credit facility as of June 30, 2011. In conjunction with our regularly scheduled borrowing base redetermination, which occurs every six months and will next be in November 2011, we expect the borrowing base amount to remain at or above the current level. Our revolving credit facility includes requirements to maintain certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of this agreement and expect to remain in compliance with these provisions in future periods. Our available borrowings under our line of credit facility provide us liquidity. In light of credit market volatility in recent years which caused many financial institutions to experience liquidity issues, we periodically review the creditworthiness of the banks that fund our credit facility.

Financial Ratios

Working Capital and Debt to Capitalization Ratio. Our working capital decreased from a surplus of $1.6 million at December 31, 2010, to a deficit of $41.9 million at June 30, 2011. The change primarily resulted from a decrease in cash and cash equivalents as we used cash received from our equity offering in 2010 to fund ongoing operations including our 2011 capital program. Working capital, which is calculated as current assets less current liabilities, can be used to measure both a company's operational efficiency and short-term financial health. The Company uses this measure to track our short-term financial position. Our debt to capitalization ratio decreased to 33% at June 30, 2011, as compared to 35% at December 31, 2010, primarily due to the increase in retained earnings from our 2011 net income.

Contractual Commitments and Obligations

We had no material changes in our contractual commitments and obligations from December 31, 2010 amounts referenced under "Contractual Commitments and Obligations" in Management's Discussion and Analysis in our Annual Report on form 10-K for the period ending December 31, 2010.

Critical Accounting Policies and New Accounting Pronouncements

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

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

The costs of unproved properties not being amortized are assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, and available geological and geophysical information. As these factors may change from period to period, our evaluation of these factors will change. Any impairment assessed is added to the cost of proved properties being amortized.

The calculation of the provision for DD&A requires us to use estimates related to quantities of proved oil and natural gas reserves and estimates of unproved properties. For both reserves estimates (see discussion below) and the impairment of unproved properties (see discussion above), these processes are subjective, and results may change over time based on current information and industry conditions. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). We did not have any outstanding derivative instruments at June 30, 2011 that materially affect this calculation.

We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. See the discussion above related to reserves estimation.

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

New Accounting Pronouncements. There are no material new accounting pronouncements that have been issued but not yet adopted as of June 30, 2011.

Forward-Looking Statements

The statements contained in this report that are not historical facts are forward-looking statements as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended. Such forward-looking statements may pertain to, among other things, financial results, capital expenditures, drilling activity, development activities, cost savings, production efforts and volumes, hydrocarbon reserves, hydrocarbon prices, cash flows, available borrowing capacity, liquidity, acquisition plans, regulatory matters, and competition. Such forward-looking statements generally are accompanied by words such as “plan,” “future,” “estimate,” “expect,” “budget,” “predict,” “anticipate,” “projected,” “believe,” or other words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management’s current plans, expectations, estimates, and assumptions, upon current market conditions, and upon engineering and geologic information available at this time, and is subject to change and to a number of risks and uncertainties, and, therefore, actual results may differ materially from those projected. Among the factors that could cause actual results to differ materially are: volatility in oil and natural gas prices; availability of services and supplies; disruption of operations and damage due to hurricanes or tropical storms; fluctuations of the prices received or demand for our oil and natural gas; the uncertainty of drilling results and reserve estimates; operating hazards; requirements for and availability of capital; conditions in the financial and credit markets; general economic conditions; changes in geologic or engineering information; changes in market conditions; competition and government regulations; as well as the risks and uncertainties discussed in this report and set forth from time to time in our other public reports, filings, and public statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

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

Price Floors - At June 30, 2011, we had natural gas price floors in effect for the contract months of July through August 2011 that cover natural gas production of 2,495,000 MMBtu from July through August 2011 with strike prices ranging between $4.55 and $4.75.

Customer Credit Risk. We are exposed to the risk of financial non-performance by customers. Our ability to collect on sales to our customers is dependent on the liquidity of our customer base. Continued volatility in both credit and commodity markets may reduce the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers and from certain customers we also obtain letters of credit, parent company guaranties if applicable, and other collateral as considered necessary to reduce risk of loss. Due to availability of other purchasers, we do not believe the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

Interest Rate Risk. Our senior notes due 2017 and 2020 have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At June 30, 2011, we had no borrowings under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 33 basis points and would not have a material adverse effect on our 2011 cash flows.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

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

Internal Control Over Financial Reporting

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

PART II. - OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 1A. Risk Factors.

There have been no material changes in our risk factors from those disclosed in our 2010 Annual Report on Form 10-K.

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

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

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
04/01/11 – 04/30/11 (1)	110	$ 40.64	---	$ ---
05/01/11 – 05/31/11 (1)	---	$ ---	---	---
06/01/11 – 06/30/11 (1)	624	$ 35.84	---	---
Total	734	$ 36.56	---	$ ---

(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.

3.1

	Amendment No. 1 to the Company's Restated Certificate of Formation (incorporated by reference as Exhibit 3.1 to Swift Energy Company's Form 8-K filed May16, 2011, File No. 1-08754).
10.1	Amendment No. 3 to the First Amended and Restated Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May16, 2011, File No. 1-08754).
10.2	First Amendment and Consent to Second Amended and Restated Credit Agreement dated May 12, 2011, among Swift Energy Company, Swift Operating, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto (incorporated by reference as Exhibit 10.01 to Swift Energy Company's Form 8-K filed May17, 2011, File No. 1-08754).
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	The following materials from the Company's quarterly Report on form 10-Q for the quarter ended March 31, 2011, formatted in Extensible Business Reporting Language (XBRL): (i) Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) Condensed Consolidated Statements of Stockholders' Equity, (iv) Condensed Consolidated Statements of Cash Flows, (v) Notes to Condensed Consolidated Financial Statements, tagged as blocks of text.

*Filed herewith

SIGNATURES

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

SWIFT ENERGY COMPANY
(Registrant)

Date: August 4, 2011	By:	/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President and Chief Financial Officer
Date: August 4, 2011	By:	/s/ Barry S. Turcotte Barry S. Turcotte Vice President, Controller and Principal Accounting Officer

Exhibit Index

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