

SWIFT ENERGY CO
Form 10-Q
May 03, 2012

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

FORM 10-Q

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

For the quarterly period ended March 31, 2012
Commission File Number 1-8754

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

Texas
(State of Incorporation)

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

16825 Northchase Drive, Suite 400
Houston, Texas 77060
(281) 874-2700

(Address and telephone number of principal executive offices)
Securities registered pursuant to Section 12(b) of the Act:

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

Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes No

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

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company

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

Yes No

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

Common Stock 42,844,639 Shares

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(\$01 Par Value)
(Class of Stock)

(Outstanding at April 30, 2012)

SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2012
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Condensed Consolidated Balance Sheets
 Swift Energy Company and Subsidiaries
 (in thousands, except share amounts)

	March 31, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ 126,789	\$ 251,696
Accounts receivable	61,199	64,392
Deferred tax asset	2,600	6,603
Other current assets	9,437	5,460
Total Current Assets	200,025	328,151
Property and Equipment:		
Property and Equipment	4,648,687	4,466,845
Less – Accumulated depreciation, depletion, and amortization	(2,660,839)	(2,599,079)
Property and Equipment, Net	1,987,848	1,867,766
Other Long-Term Assets	15,752	16,552
Total Assets	\$ 2,203,625	\$ 2,212,469
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	\$ 78,798	\$ 95,966
Accrued capital costs	95,566	98,844
Accrued interest	11,865	12,459
Undistributed oil and gas revenues	6,448	4,525
Total Current Liabilities	192,677	211,794
Long-Term Debt	719,875	719,775
Deferred Tax Liabilities	205,025	206,567
Asset Retirement Obligation	69,552	67,115
Other Long-Term Liabilities	10,853	10,709
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, 43,341,063 and 42,969,546 shares issued, and 42,828,821 and 42,485,075 shares outstanding, respectively	433	430
Additional paid-in capital	733,592	726,956
Treasury stock held, at cost, 512,242 and 484,471 shares, respectively	(13,686)	(12,350)
Retained earnings	285,043	281,473
Accumulated other comprehensive income, net of income tax	261	---
Total Stockholders' Equity	1,005,643	996,509
Total Liabilities and Stockholders' Equity	\$ 2,203,625	\$ 2,212,469

See accompanying Notes to Condensed Consolidated Financial Statements.

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

	Three Months Ended March 31,	
	2012	2011
Revenues:		
Oil and gas sales	\$136,142	\$144,201
Price-risk management and other, net	(264)	(123)
Total Revenues	135,878	144,078
Costs and Expenses:		
General and administrative, net	11,883	10,443
Depreciation, depletion, and amortization	61,363	52,921
Accretion of asset retirement obligation	1,112	1,136
Lease operating cost	29,213	25,384
Severance and other taxes	12,960	13,313
Interest expense, net	13,465	8,388
Total Costs and Expenses	129,996	111,585
Income from Continuing Operations Before Income Taxes	5,882	32,493
Provision for Income Taxes	2,312	12,244
Income from Continuing Operations	3,570	20,249
Loss from Discontinued Operations, net of taxes	---	(68)
Net Income	\$3,570	\$20,181
Per Share Amounts-		
Basic: Income from Continuing Operations	\$0.08	\$0.47
Loss from Discontinued Operations, net of taxes	---	---
Net Income	\$0.08	\$0.47
Diluted: Income from Continuing Operations	\$0.08	\$0.47
Loss from Discontinued Operations, net of taxes	---	---
Net Income	\$0.08	\$0.47
Weighted Average Shares Outstanding - Basic	42,674	42,190

See accompanying Notes to Condensed Consolidated Financial Statements.

Condensed Consolidated Statements of Comprehensive Income (Unaudited)
 Swift Energy Company and Subsidiaries
 (in thousands)

	Three Months Ended March 31,	
	2012	2011
Net Income:	\$3,570	\$20,181
Other Comprehensive Income:		
Unrealized gains related to price risk management transactions, before taxes	212	19
Provision for income taxes	77	7
Unrealized gains related to price risk management transactions, net of taxes	135	12
Less: reclassification of (gains) losses on price risk management transactions to net income, before taxes	198	(167)
(Provision) benefit for income taxes	72	(60)
Reclassification of (gains) losses on price risk management transactions to net income, net of taxes	126	(107)
Other comprehensive income (loss), before income taxes	410	(148)
Provision (benefit) for income taxes	149	(54)
Other comprehensive income (loss), net of taxes	261	(94)
Comprehensive Income	\$3,831	\$20,087

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, 2010	\$424	\$706,857	\$(9,778)	\$182,652	\$ (138)	\$880,017
Stock issued for benefit plans (37,068 shares)	-	791	821	-	-	1,612
Stock options exercised (130,902 shares)	1	1,150	-	-	-	1,151
Purchase of treasury shares (80,014 shares)	-	-	(3,393)	-	-	(3,393)
Tax benefits from stock compensation	-	333	-	-	-	333
Employee stock purchase plan (49,089 shares)	1	999	-	-	-	1,000
Issuance of restricted stock (348,972 shares)	4	(4)	-	-	-	-
Amortization of stock compensation	-	16,830	-	-	-	16,830
Net Income	-	-	-	98,821	-	98,821
Other comprehensive income	-	-	-	-	138	138
Balance, December 31, 2011	\$430	\$726,956	\$(12,350)	\$281,473	-	\$996,509
Stock issued for benefit plans (50,987 shares) (2)	-	354	1,300	-	-	1,654
Stock options exercised (19,077 shares) (2)	-	253	-	-	-	253
Purchase of treasury shares (78,758 shares)	-	-	(2,636)	-	-	(2,636)
Employee stock purchase plan (42,624 shares) (2)	-	1,076	-	-	-	1,076
Issuance of restricted stock (309,816 shares) (2)	3	(3)	-	-	-	-
Amortization of share-based compensation (2)	-	4,956	-	-	-	4,956
Net Income (2)	-	-	-	3,570	-	3,570
Other comprehensive income (2)	-	-	-	-	261	261
Balance, March 31, 2012 (2)	\$433	\$733,592	\$(13,686)	\$285,043	\$ 261	\$1,005,643

(1) \$.01 par value.

(2) Unaudited

See accompanying Notes to Condensed Consolidated Financial Statements.

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

(in thousands)	Three Months Ended March 31,	
	2012	2011
Cash Flows from Operating Activities:		
Net income	\$3,570	\$20,181
Plus loss from discontinued operations, net of taxes	---	68
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion, and amortization	61,363	52,921
Accretion of asset retirement obligation	1,112	1,136
Deferred income taxes	2,312	10,822
Stock-based compensation expense	3,629	2,684
Other	(2,889)	(8,589)
Change in assets and liabilities-		
(Increase) decrease in accounts receivable	3,193	(13,612)
Decrease in accounts payable and accrued liabilities	(7,913)	(3,112)
Increase in income taxes payable	---	2
Decrease in accrued interest	(594)	(785)
Cash provided by operating activities – continuing operations	63,783	61,716
Cash provided by operating activities – discontinued operations	---	99
Net Cash Provided by Operating Activities	63,783	61,815
Cash Flows from Investing Activities:		
Additions to property and equipment	(187,915)	(131,911)
Proceeds from the sale of property and equipment	532	13
Cash used in investing activities – continuing operations	(187,383)	(131,898)
Cash provided by investing activities – discontinued operations	---	5,000
Net Cash Used in Investing Activities	(187,383)	(126,898)
Cash Flows from Financing Activities:		
Net proceeds from issuances of common stock	1,329	1,742
Purchase of treasury shares	(2,636)	(3,262)
Cash used in financing activities – continuing operations	(1,307)	(1,520)
Cash provided by financing activities – discontinued operations	---	---
Net Cash Used in Financing Activities	(1,307)	(1,520)
Net Decrease in Cash and Cash Equivalents	(124,907)	(66,603)
Cash and Cash Equivalents at Beginning of Period	251,696	86,367
Cash and Cash Equivalents at End of Period	\$126,789	\$19,764
Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	\$13,415	\$8,741
Cash paid during period for income taxes	\$---	\$1,420

See accompanying Notes to Condensed Consolidated Financial Statements.

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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, 2011 as filed with the Securities and Exchange Commission. The accompanying condensed consolidated financial statements, for the three months ended March 31, 2012, include a reduction of approximately \$0.9 million to oil and gas revenue and approximately \$0.8 million of additional severance tax expense. Both of these items related to prior year activity and were not deemed material with respect to either the results of prior year or the anticipated results and the trend of earnings for fiscal year 2012.

(2) Summary of Significant Accounting Policies

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

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

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

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

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
 - estimates related to the collectability of accounts receivable and the credit worthiness of our customers,
- estimates of the counterparty bank risk related to letters of credit that our customers may have issued on our behalf,
 - estimates of future costs to develop and produce reserves,

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- 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 three months ended March 31, 2012 and 2011, such internal costs capitalized totaled \$8.3 million and \$7.2 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the three months ended March 31, 2012 and 2011, capitalized interest on unproved properties totaled \$2.0 million and \$1.9 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

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

(in thousands)	March 31, 2012	December 31, 2011
Property and Equipment		
Proved oil and gas properties	\$ 4,521,651	\$ 4,343,867
Unproved oil and gas properties	87,327	84,146
Furniture, fixtures, and other equipment	39,709	38,832
Less – Accumulated depreciation, depletion, and amortization	(2,660,839)	(2,599,079)
Property and Equipment, Net	\$ 1,987,848	\$ 1,867,766

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

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

We compute the provision for depreciation, depletion, and amortization (“DD&A”) of oil and natural gas properties using the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties—including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties—by an overall rate determined by dividing the physical units of oil and natural gas produced during the period by the total estimated units of proved oil and natural gas reserves at the beginning of the period. This calculation is done on a country-by-country basis, and the period over which we will amortize these properties is dependent on our production from these properties in future years. Furniture, fixtures, and

other equipment are recorded at cost and are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between 2 and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

Geological and geophysical (“G&G”) costs incurred on developed properties are recorded in “Proved properties” and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in “Unproved properties” and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using the preceding 12-months' average price based on closing prices on the first day of each month, adjusted for price differentials and 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 in place at March 31, 2011 and December 31, 2011 consisted of 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 reasonably possible that non-cash write-downs of oil and natural gas properties would 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 would occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties if a decrease in oil and/or natural gas prices were to occur.

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Swift Energy uses the entitlement method of accounting in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying condensed consolidated balance sheets. Natural gas balancing receivables are reported in "Other current assets" on the accompanying condensed consolidated balance sheets when our ownership share of production exceeds sales. As of March 31, 2012 and December 31, 2011, we did not have any material natural gas imbalances.

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

Accounts Receivable. We assess the collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At March 31, 2012 and December 31, 2011, we had an allowance for doubtful accounts of approximately \$0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts Receivable" balance on the accompanying condensed consolidated balance sheets.

At March 31, 2012 our "Accounts Receivable" balance included \$49.9 million for oil and gas sales, \$6.7 million for joint interest owners and \$4.6 million for other receivables. At December 31, 2011 our "Accounts Receivable" balance included \$54.7 million for oil and gas sales, \$4.2 million for joint interest owners and \$5.6 million for other receivables.

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

The 7-1/8% senior notes due 2017 mature on June 1, 2017, and the balance of their issuance costs at March 31, 2012, was \$2.5 million, net of accumulated amortization of \$1.7 million. The 8-7/8% senior notes due 2020 mature on January 15, 2020, and the balance of their issuance costs at March 31, 2012, was \$4.3 million, net of accumulated amortization of \$0.8 million. The 7-7/8% senior notes due 2022 mature on March 1, 2022, and the balance of their issuance costs at March 31, 2012, was \$4.6 million, net of accumulated amortization of \$0.1 million. The issuance costs associated with our revolving credit facility, which was revised and extended in May 2011, have been capitalized and are being amortized over the life of the facility. The balance of revolving credit facility issuance costs at March 31, 2012, was \$3.3 million, net of accumulated amortization of \$4.2 million.

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 March 31, 2012 and 2011, we recognized a net loss of \$0.4 million and \$0.2 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying condensed consolidated statements of operations. Had these losses been recognized in the oil and gas sales account they would not have materially changed our per unit sales prices received. At March 31, 2012, the Company had \$0.3 million in derivative gains recorded in "Accumulated other comprehensive gain, net of income tax" on the accompanying condensed consolidated balance sheet. The ineffectiveness reported in "Price-risk management and other, net" for the three months ended March 31, 2012 and 2011 was not material.

At March 31, 2012, we had oil price floors in effect for the contract months of April through May 2012 that cover oil production of 270,500 Bbls with strike prices ranging between \$100.00 and \$105.00.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive income, net of income tax." When the hedged transactions are recorded upon the actual sale of the oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive income, net of income tax" on the accompanying condensed consolidated balance sheets and are recorded in "Price-risk management and other, net" on the accompanying condensed consolidated statements of operations. The fair values of our derivatives are computed using the Black-Scholes-Merton option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments at March 31, 2012 and December 31, 2011, was \$0.8 million and \$0.1 million, respectively and was recognized on the accompanying condensed consolidated balance sheet in "Other current assets."

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees, to the extent they do not exceed actual costs incurred, are recorded as a reduction to "General and administrative, net." Our supervision fees are based on COPAS guidelines. The amount of supervision fees charged for the first three months of 2012 and 2011 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate was \$2.8 million and \$3.5 million in the first three months of 2012 and 2011, 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 \$3.2 million at March 31, 2012 and \$3.6 million at December 31, 2011.

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. As a result of adopting this guidance on January 1, 2007, we reported a \$1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to other long-term liabilities. If recognized, these tax benefits would fully impact our effective tax rate. This benefit is likely to be recognized within the next 12 months due to the lapse of the applicable statute of limitations.

We do not believe the total of unrecognized tax positions will significantly increase or decrease during the next 12 months.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of March 31, 2012, 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 2005, and our Texas franchise tax returns after 2006 remain subject to examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

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

	March 31, 2012	December 31, 2011
Trade accounts payable (1)	\$ 39,219	\$ 42,080
Accrued operating expenses	15,540	15,833
Accrued payroll costs	4,957	14,345
Asset retirement obligation – current portion	9,303	9,279
Accrued taxes	7,446	7,604
Other payables	2,333	6,825
Total accounts payable and accrued liabilities	\$ 78,798	\$ 95,966

(1) Included in “trade accounts payable” are liabilities of approximately \$22.1 million and \$18.7 million at March 31, 2012 and December 31, 2011, respectively, for outstanding checks. This represents the amounts by which checks were issued, but not presented by vendors to the Company’s banks for collection, exceeded balances in the applicable disbursement bank accounts.

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

Restricted Cash. These balances primarily include amounts held in escrow accounts to satisfy domestic plugging and abandonment obligations. As of March 31, 2012 and December 31, 2011, these assets include approximately \$1.0 million and \$1.3 million, respectively. 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 Income, 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

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distributions to the owners of the Company. At March 31, 2012, the Company had \$0.3 million in gains recorded in “Accumulated other comprehensive income, net of income tax” on the accompanying condensed consolidated balance sheet. The components of accumulated other comprehensive income 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, 2011	\$ ---	\$ ---	\$ ---
Change in fair value of cash flow hedges	212	(77)	135
Effect of cash flow hedges settled during the period	198	(72)	126
Other comprehensive income at March 31, 2012	\$ 410	\$ (149)	\$ 261

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 "Property and equipment" balance on our accompanying condensed consolidated balance sheets. 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):

	2012	2011
Asset Retirement Obligation recorded as of January 1	\$ 76,393	\$ 78,879
Accretion expense	1,112	1,136
Liabilities incurred for new wells and facilities construction	282	139
Reductions due to sold and abandoned wells	(79)	(32)
Revisions in estimates	1,147	(1,385)
Asset Retirement Obligation as of March 31	\$ 78,855	\$ 78,737

At March 31, 2012 and December 31, 2011, approximately \$9.3 million of our asset retirement obligation was classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying condensed consolidated balance sheets.

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 adopted this guidance for the period ending March 31, 2012, which can be seen in our "Statement of Comprehensive Income."

(3) Share-Based Compensation

We have various types of share-based compensation plans. Refer to Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2011, 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 market value on the exercise date over the exercise price of the options. We receive an additional tax deduction when restricted stock vests at a higher value than the value used to recognize compensation expense at the date of grant. In accordance with guidance contained in FASB ASC 718, we are required to report excess tax benefits from the award of equity instruments as financing cash flows. For the three months ended March 31, 2012 and 2011,

we did not recognize any excess tax benefit or shortfall.

Net cash proceeds from the exercise of stock options were \$0.3 million and \$0.7 million for the three months ended March 31, 2012 and 2011, respectively. The actual income tax benefit from stock option exercises was \$0.1 million and \$0.9 million for the three months ended March 31, 2012 and 2011, 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 \$3.4 million and \$2.5 million for the three months ended March 31, 2012 and 2011, respectively. Share-based compensation recorded in lease operating cost was \$0.1 million for the three months ended March 31, 2012 and 2011, respectively. We also capitalized \$1.3 million and \$1.0 million of share-based compensation for the three months ended March 31, 2012 and 2011. We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

Stock Options

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

	Three Months Ended			
	March 31,			
	2012		2011	
Dividend yield	0	%	0	%
Expected volatility	61.2	%	58.8	%
Risk-free interest rate	0.8	%	1.9	%
Expected life of options (in years)	4.4		3.9	
Weighted-average grant-date fair value	\$ 15.96		\$ 19.33	

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 2012 and 2011 stock option grants.

At March 31, 2012, we had \$6.1 million of unrecognized compensation cost related to stock options, which is expected to be recognized over a weighted-average period of 1.5 years. The following table represents stock option activity for the three months ended March 31, 2012:

	Shares	Wtd. Avg. Exercise Price
Options outstanding, beginning of period	1,375,281	\$ 32.46
Options granted	323,439	\$ 32.60
Options canceled	(17,199)	\$ 47.15
Options exercised	(27,116)	\$ 18.64
Options outstanding, end of period	1,654,405	\$ 32.56
Options exercisable, end of period	1,065,306	\$ 31.45

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at March 31, 2012 was \$5.7 million and 6.5 years and \$5.4 million and 5.0 years, respectively. The total intrinsic value of options exercised during the three months ended March 31, 2012 was \$0.4 million.

Restricted Stock

The plans, as described in Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2011, allow for the issuance of restricted stock awards that may not be sold or otherwise transferred until certain restrictions have lapsed. The unrecognized compensation cost related to these awards is expected to be expensed over the period the restrictions lapse (generally one to three years).

The compensation expense for these awards was determined based on the closing market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of March 31, 2012, we had unrecognized compensation expense of \$27.3 million related to restricted stock awards which is expected to be

recognized over a weighted-average period of 1.5 years. The grant date fair value of shares vested during the three months ended March 31, 2012 was \$8.3 million.

The following table represents restricted stock activity for the three months ended March 31, 2012:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	834,703	\$ 31.89
Restricted shares granted	474,200	\$ 32.62
Restricted shares canceled	(9,053)	\$ 32.33
Restricted shares vested	(309,816)	\$ 26.73
Restricted shares outstanding, end of period	990,034	\$ 33.85

(4) Earnings Per Share

The Company computes earnings per share in accordance with FASB ASC 260-10. Under the guidance, unvested restricted stock grants 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 month periods ended March 31, 2012 and 2011 assumes, as of the beginning of the period, exercise of stock options using the treasury stock method. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the three month periods ended March 31, 2012 and 2011, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the three month periods ended March 31, 2012 and 2011 (in thousands, except per share amounts):

	Three Months Ended March 31, 2012			Three Months Ended March 31, 2011		
	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	\$3,570	42,674		\$20,249	42,190	
Less: (Income) loss from continuing operations allocated to unvested shares	(74)	---		(370)	---	
Income from continuing operations allocated to common shares	\$3,496	42,674	\$0.08	\$19,879	42,190	\$0.47
Dilutive Securities:						
Plus: Income from continuing operations allocated to unvested	74	---		370	---	

shares

Less: (Income) loss from
continuing operations

re-allocated to unvested shares	(74)	---	(368)	---
Stock Options	---		200	---		319

Diluted EPS:

Income from continuing
operations allocated to common
shares, and assumed share
conversions

\$3,496	42,874	\$0.08	\$19,881	42,509	\$0.47
---------	--------	--------	----------	--------	--------

Options to purchase approximately 1.7 million shares at an average exercise price of \$32.56 were outstanding at March 31, 2012, while options to purchase approximately 1.5 million shares at an average exercise price of \$32.93 were outstanding at March 31, 2011. Approximately 0.9 million and 0.6 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months ended March 31, 2012 and 2011, respectively, because these stock options were antidilutive, in that the sum of the stock option price, unrecognized compensation expense and excess tax benefits recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during those periods.

(5) Long-Term Debt

Our long-term debt as of March 31, 2012 and December 31, 2011, was as follows (in thousands):

	March 31, 2012	December 31, 2011
7-1/8% senior notes due 2017	\$ 250,000	\$ 250,000
8-7/8% senior notes due 2020 (1)	221,940	221,873
7-7/8% senior notes due 2022 (1)	247,935	247,902
Bank Borrowings	---	---
Long-Term Debt (1)	\$ 719,875	\$ 719,775

(1) Amounts are shown net of debt discount

The maturities on our long-term debt are \$250.0 million in 2017, \$225.0 million in 2020 and \$250.0 million in 2022.

We have capitalized interest on our unproved properties in the amount of \$2.0 million and \$1.9 million for the three months ended March 31, 2012 and 2011, respectively.

Bank Borrowings. In May 2011, we renewed and extended our \$500 million credit facility with a syndicate of ten banks through May 12, 2016, which may be increased by up to \$200 million to a maximum aggregate facility amount of \$700 million, subject to additional lender commitments and other terms of the credit agreement. As of March 31, 2012, our borrowing base was \$325 million and our commitment amount was \$300 million. In May 2012, in conjunction with our regularly scheduled borrowing base redetermination, which occurs every six months, our borrowing base was increased to \$375 million and we elected to keep our commitment amount at \$300 million.

At March 31, 2012 and December 31, 2011 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 March 31, 2012, 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. As of March 31, 2012 we were 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.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled \$0.6 million and \$0.6 million for the three months ended March 31, 2012 and 2011, respectively. The amount of

commitment fees included in interest expense, net was \$0.4 million for the three month periods ended March 31, 2012 and 2011, respectively.

Senior Notes Due 2022. These notes consist of \$250 million of 7-7/8% senior notes issued at 99.156% of par, which equates to an effective yield to maturity of 8%. The notes were issued on November 30, 2011 with an original discount of \$2.1 million and will mature on March 1, 2022. The original discount of \$2.1 million is recorded in “Long-Term Debt” on our condensed consolidated balance sheet and will be amortized over the life of the note. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Payment of interest on these notes is payable semi-annually on March 1 and September 1 and commenced on March 1, 2012. On or after March 1, 2017, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.938% of principal, declining in twelve-month intervals to 100% in 2020 and thereafter. In addition, prior to March 1, 2015, 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 107.875% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately \$4.8 million of debt issuance costs related to these notes, which is included in “Other Long-Term Assets” on the accompanying condensed consolidated balance sheet 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 were in compliance with the provisions of the indenture governing these senior notes as of March 31, 2012.

Under the terms of the sale of the Senior Notes due 2022, Swift was required to offer to exchange these notes for registered notes with the same terms. In April 2012 we commenced the exchange offer for all of the Senior Notes due 2022, and expect the exchange to be completed by May 2012.

Interest expense on the 7-7/8% senior notes due 2022, including amortization of debt issuance costs and debt discount, totaled \$5.0 million for the three months ended March 31, 2012.

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 note. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Payment of 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 were in compliance with the provisions of the indenture governing these senior notes as of March 31, 2012.

Interest expense on the 8-7/8% senior notes due 2020, including amortization of debt issuance costs and debt discount, totaled \$5.2 million and \$5.1 million for the three months ended March 31, 2012 and 2011, 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. Payment of 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 were in compliance with the provisions of the indenture governing these senior notes as of March 31, 2012.

Interest expense on the 7-1/8% senior notes due 2017, including amortization of debt issuance costs, totaled \$4.6 million and \$4.5 million for the three months ended March 31, 2012 and 2011, 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 December 31, 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. The Company has written off its remaining unused New Zealand tax losses.

Our loss from discontinued operations, net of taxes was less than \$0.1 million for the three months ended March 31, 2011, which equated to \$0.00 per basic and diluted share for the same period. Our cash provided by operating activities – discontinued operations was less than \$0.1 million for the three months ended March 31, 2011.

(7) Acquisitions and Dispositions

There were no material acquisitions or dispositions in the three months ended March 31, 2012 and 2011, respectively.

(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.

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments.

The fair value of the bank borrowings approximate the carrying amounts as of March 31, 2012 and December 31, 2011, and was determined based upon variable interest rates currently available to us for borrowings with similar terms.

Based upon quoted market prices as of March 31, 2012 and December 31, 2011, the fair value and carrying value of our senior notes was as follows (in millions):

	March 31, 2012		December 31, 2011	
	Fair Value	Carrying Value	Fair Value	Carrying Value
7-1/8% senior notes due 2017	\$ 257.5	\$ 250.0	\$ 254.8	\$ 250.0
8-7/8% senior notes due 2020	\$ 243.6	\$ 221.9	\$ 239.6	\$ 221.9
7-7/8% senior notes due 2022	\$ 255.0	\$ 247.9	\$ 252.8	\$ 247.9

Our senior notes due 2017, 2020 and 2022 are stated at cost on our financial statements and are traded in an active market with observable inputs. If we recorded these notes at fair value they would be level 2 in our fair value hierarchy since their value is based on similar assets and they are in a market with limited trading.

The following table presents our assets that are measured at fair value as of March 31, 2012 and December 31, 2011 and are categorized using the fair value hierarchy. The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (in millions):

	Fair Value Measurements at			
	Total	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
March 31, 2012				
Oil Floors	\$ 0.8	\$ ---	\$ 0.8	\$ ---
December 31, 2011				
Oil Floors	\$ 0.1	\$ ---	\$ 0.1	\$ ---

Our derivatives, measured at fair value in the table above, are recorded in “Other current assets” on the accompanying condensed consolidated balance sheet.

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, 2020 and 2022. The guarantees on our senior notes due 2017, 2020 and 2022 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

	March 31, 2012				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
ASSETS					
Current assets	\$---	\$200,004	\$21	\$---	\$ 200,025
Property and equipment	---	1,987,848	---	---	1,987,848
Investment in subsidiaries (equity method)	1,005,643	---	920,195	(1,925,838)	---
Other assets	---	15,752	85,429	(85,429)	15,752
Total assets	\$1,005,643	\$2,203,604	\$1,005,645	\$(2,011,267)	\$ 2,203,625
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	\$---	\$192,675	\$2	\$---	\$ 192,677
Long-term liabilities	---	1,090,734	---	(85,429)	1,005,305
Stockholders' equity	1,005,643	920,195	1,005,643	(1,925,838)	1,005,643
Total liabilities and stockholders' equity	\$1,005,643	\$2,203,604	\$1,005,645	\$(2,011,267)	\$ 2,203,625

	December 31, 2011				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
ASSETS					
Current assets	\$---	\$328,130	\$21	\$---	\$ 328,151
Property and equipment	---	1,867,766	---	---	1,867,766
Investment in subsidiaries (equity method)	996,509	---	911,061	(1,907,570)	---
Other assets	---	16,552	85,429	(85,429)	16,552
Total assets	\$996,509	\$2,212,448	\$996,511	\$(1,992,999)	\$ 2,212,469

LIABILITIES AND STOCKHOLDERS'
EQUITY

Current liabilities	\$---	\$211,792	\$2	\$---	\$ 211,794
Long-term liabilities	---	1,089,595	---	(85,429)	1,004,166
Stockholders' equity	996,509	911,061	996,509	(1,907,570)	996,509
Total liabilities and stockholders' equity	\$996,509	\$2,212,448	\$996,511	\$(1,992,999)	\$ 2,212,469

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Condensed Consolidating Statements of Income

(in thousands)

	Three Months Ended March 31, 2012				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Revenues	\$---	\$135,878	\$---	\$---	\$135,878
Expenses	---	129,996	---	---	129,996
Income before the following:	---	5,882	---	---	5,882
Equity in net earnings of subsidiaries	3,570	---	3,570	(7,140)	---
Income from continuing operations, before income taxes	3,570	5,882	3,570	(7,140)	5,882
Income tax provision	---	2,312	---	---	2,312
Net income	\$3,570	\$3,570	\$3,570	\$ (7,140)	\$ 3,570
Total comprehensive income	\$3,831	\$3,831	\$---	\$ (3,831)	\$ 3,831

(in thousands)

	Three Months Ended March 31, 2011				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Revenues	\$---	\$144,078	\$---	\$---	\$144,078
Expenses	---	111,585	---	---	111,585
Income before the following:	---	32,493	---	---	32,493
Equity in net earnings of subsidiaries	20,181	---	20,249	(40,430)	---
Income from continuing operations, before income taxes	20,181	32,493	20,249	(40,430)	32,493
Income tax provision	---	12,244	---	---	12,244
Income from continuing operations	20,181	20,249	20,249	(40,430)	20,249
Loss from discontinued operations, net of taxes	---	---	(68)	---	(68)
Net income	\$20,181	\$20,249	\$20,181	\$ (40,430)	\$ 20,181
Total comprehensive income	\$20,087	\$20,087	\$---	\$ (20,087)	\$ 20,087

Condensed Consolidating Statements of Cash Flows

(in thousands)	Three Months Ended March 31, 2012				
	Swift Energy Company (Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Company Consolidated
Cash flow from operations	\$---	\$63,783	\$--	\$--	\$ 63,783
Cash flow from investing activities	---	(187,383)	---	---	(187,383)
Cash flow from financing activities	---	(1,307)	---	---	(1,307)
Net decrease in cash	---	(124,907)	---	--	(124,907)
Cash, beginning of period	---	251,677	19	---	251,696
Cash, end of period	\$---	\$126,770	\$19	\$--	\$ 126,789

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

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, 2011 and 2010. Unless otherwise noted, both historical information for all periods and forward-looking information provided in this Management's Discussion and Analysis relates solely to our continuing operations located in the United States, and excludes our New Zealand discontinued operations. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 29 of this report.

Overview

We are an independent oil and natural gas company formed in 1979, and we are engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from our Texas properties as well as onshore and inland waters of Louisiana. We are one of the largest producers of crude oil in the state of Louisiana, and hold a large acreage position in Texas prospective for Eagle Ford shale and Olmos tight sands development. Oil production accounted for 32% of our first quarter 2012 production and 73% of our oil and gas revenues, and combined production of both oil and natural gas liquids ("NGLs") constituted 45% of our first quarter 2012 production and 85% 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 first quarter of 2012.

First Quarter 2012 Highlights

- **Production:** Our production volumes increased by 6% in the first quarter of 2012 when compared to volumes in the same period in 2011 as natural gas production volumes increased by 17%, NGL volumes increased by 8%, while oil volumes decreased 10%. Sequentially, production volumes increased 4% in the first quarter of 2012 compared to fourth quarter of 2011 levels as natural gas production volumes increased by 17%, NGL volumes decreased by 13% and oil volumes decreased by 7%. The overall increase in natural gas and NGL production have come from our South Texas area.
- **Pricing:** Our weighted average sales price in the first quarter of 2012 decreased by 11% and 16% when compared to levels in the first quarter of 2011 and the fourth quarter of 2011, respectively. When compared to the first quarter of 2011, natural gas prices declined 43%, along with a decline in NGL prices of 7%, and were offset somewhat by a 14% increase in oil prices. When compared to the fourth quarter of 2011, natural gas prices declined 36%, along with a decline in NGL prices of 14%, while oil prices were flat.
- **Cash provided by operating activities:** This GAAP measure increased by \$2.1 million or 3%, when compared to first quarter of 2011 levels due to negative working capital adjustments in the 2011 period. As compared to fourth quarter of 2011 levels, our cash provided by operating activities decreased by \$20.8 million, or 25%, due to lower revenues and income in the 2012 period.
- **2012 capital expenditures:** Our capital expenditures on a cash flow basis were \$187.9 million in the first quarter of 2012, compared to \$131.9 million in the first quarter of 2011, and \$136.6 million in the fourth quarter of 2011. These increases were mainly due to additional drilling and completion activity in our South Texas core region as we drilled six horizontal wells in our AWP Olmos field, two wells in our AWP Eagle Ford field, two wells in our Fasken Eagle Ford field and five wells in our Artesia Eagle Ford field, helping us evaluate Eagle Ford and Olmos acreage positions in those areas. We also drilled two wells in our Southeast Louisiana area. These 2012 expenditures were primarily funded by \$63.8 million of cash provided by operating activities and the remaining cash proceeds from our notes offering in November 2011.

2012 Strategy and Outlook

- Focus on oil and liquids properties with expanded capital budget: Our inventory of drilling locations allows us to be flexible in scheduling upcoming wells in South Texas to focus on natural gas liquids. . Having fulfilled our near-term obligations on most of our acreage prospective for dry natural gas production, we will be concentrating on our higher return, liquids rich acreage almost exclusively this year. Our 2012 capital expenditures are currently estimated to be \$575 to \$625 million.
- Increase production: Our current 2012 goal is to increase production volumes by 14% to 20% over 2011 volumes.
 - Increase reserves: Our current 2012 goal is to increase proved reserves volumes by 10% to 15%.
- Financial flexibility: At March 31, 2012, we have approximately \$127 million of cash on hand and a commitment amount of \$300.0 million under our credit agreement. These amounts give us the financial flexibility to execute our 2012 strategy.
- Added midstream capacity and third party providers: Additional dedicated transportation and processing through a newly constructed third-party pipeline of a mid-stream provider (handling natural gas production from our AWP Eagle Ford and Olmos areas) became operational at the beginning of October 2011. In our Fasken Eagle Ford area, we also secured capacity on a pipeline built in late 2010 by a midstream provider. In both AWP Eagle Ford and Fasken Eagle Ford areas, we have secondary transportation outlets available if capacity is restricted on our primary outlets.
- Highly skilled workforce: We have built a strong organization of highly skilled oil and gas professionals and also engage experienced and qualified consultants. These professionals are critical to executing our 2012 goals.
- Capital cost saving measures: We have realized significant capital cost savings in South Texas related to pad drilling, well construction and completion re-design, sourcing and transportation of proppants as well as increased productivity of our dedicated frac spread and crew. Our supply chain program continues to be extremely important and the relationships that we have developed with our service providers are critical to our 2012 program execution.

2012 Known Trends and Uncertainties Affecting our Business

- Recent declines in natural gas prices: Several factors such as increases in shale and tight sands production, mild winter weather, and relatively high natural gas storage levels have led to declining natural gas prices in the fourth quarter of 2011 and particularly at the end of the first quarter of 2012. We have not hedged our natural gas production and will receive a market price for natural gas in 2012. Lower natural gas prices equate to lower revenue and cash flows and might lead to reductions in our borrowing capacity. As natural gas makes up a large percentage of our reserves base on a Boe basis, lower natural gas prices in 2012 could lead to potential reserve reductions which could result in full-cost ceiling write-downs.
 - Employee retention: As our competitors expand their workforce, we must focus more attention on keeping our highly skilled employees. There has been and will be constant cost pressure to retain and hire these employees and these costs do not decline as rapidly and significantly as hydrocarbon prices.
- Oilfield services shortages and delays: During periods of increased levels of exploration and production in particular areas, such as we are currently experiencing in the South Texas areas, 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.
- Long-term capital commitments: In an effort to secure longer-term agreements on drilling rigs, fracturing services, equipment and supplies, our capital commitments have become more significant than in prior periods. Although these ensure that rigs and crews we need are available to use, these commitments may also reduce our liquidity in a downturn and may require us to pay above market prices for services in a declining service price environment.
- High concentration of sales with one customer: Over the last several years, a large portion of our oil and gas sales have been to Shell Oil Corporation and affiliates and we expect to continue this relationship in the future. We believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of their business.

Results of Operations

Revenues and Expenses — Three Months Ended March 31, 2012 and 2011

Our revenues in the first quarter of 2012 decreased by 6% compared to revenues in the first quarter of 2011, due to lower oil production and lower natural gas pricing, partially offset by higher natural gas production and higher oil pricing. Average oil prices that we received were 14% higher than those received during the first quarter of 2011, while natural gas prices were 43% lower, and NGL prices were 7% lower.

Crude oil production was 32% and 37% of our production volumes in the first quarter of 2012 and 2011, respectively. Crude oil sales were 73% and 67% of oil and gas sales in the first quarter of 2012 and 2011, respectively. Natural gas production was 55% and 50% of our production volumes in the first quarter of 2012 and 2011, respectively. Natural gas sales were 15% and 21% of oil and gas sales in the first quarter of 2012 and 2011, respectively. The remaining production in each year was from natural gas liquids (NGLs).

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 March 31, 2012 and 2011:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2012	2011	2012	2011
	S. E. Louisiana	\$58.2	\$71.0	592
South Texas	65.7	48.7	2,021	1,340
Central Louisiana / East Texas	12.0	15.4	182	256
Other	0.2	9.1	4	180
Total	\$136.1	\$144.2	2,799	2,646

In the first quarter of 2012, our \$8.1 million decrease in oil, NGL, and natural gas sales resulted from:

- Price variances that had a \$4.6 million unfavorable impact on sales, with a decrease of \$1.3 million due to the 7% decrease in NGL prices, and a decrease of \$15.1 million attributable to the 43% decrease in natural gas prices, offset by an increase of \$11.8 million due to the 14% increase in average oil prices received,
- Volume variances that had a \$3.4 million unfavorable impact on sales, with a \$10.0 million decrease due to the 0.1 million Bbl decrease in oil production volumes, offset by a \$1.4 million increase attributable to the less than 0.1 million Bbl increase in NGL production volumes, and a \$5.2 million increase due to the 1.4 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, for the three months ended March 31, 2012 and 2011:

Oil (MBbl)	Production Volume			Average Price		
	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
884	376	9.2	2,799	\$ 111.99	\$ 45.30	\$ 2.18

Three
Months
Ended
March 31,
2012

Three
Months
Ended
March 31,
2011

985	348	7.9	2,646	\$ 98.61	\$ 48.87	\$ 3.82
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During the first quarter of 2012, we recorded a net loss of \$0.4 million related to our derivative activities, while during the first quarter of 2011 we recorded a net loss of \$0.2 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 \$111.55 and \$98.31 for the first quarters of 2012 and 2011, respectively, and our average natural gas price would have been \$2.18 and \$3.83 for the first quarters of 2012 and 2011, respectively.

Costs and Expenses.

Expenses. Our expenses in the first quarter of 2012 increased \$18.4 million, or 16%, compared to those in the first quarter of 2011 for the reasons noted below.

Lease Operating Expenses (“LOE”). These expenses increased \$3.8 million, or 15%, compared to the level of such expenses in the first quarter of 2011. Lease operating costs increased during 2012 due to higher workover costs in Southeast Louisiana, and additional costs in our South Texas region for salt water disposal, labor, and repairs and maintenance. Our lease operating costs per Boe produced were \$10.44 and \$9.59 for the first quarters of 2012 and 2011, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses increased \$8.4 million, or 16% from those in the first quarter of 2011. 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 \$21.92 and \$20.00 in the first quarters of 2012 and 2011, respectively, resulting from increases in the per unit cost of reserves additions in 2012.

General and Administrative Expenses, Net. These expenses increased \$1.4 million, or 14%, from the level of such expenses in the first quarter of 2011. The increase was primarily due to higher salaries and burdens in the first quarter of 2012, partially offset by higher capitalized amounts. For the first quarters of 2012 and 2011, our capitalized general and administrative costs totaled \$8.3 million and \$7.2 million, respectively. Our net general and administrative expenses per Boe produced increased to \$4.25 per Boe in the first quarter of 2012 from \$3.95 per Boe in the first quarter of 2011. The portion of supervision fees recorded as a reduction to general and administrative expenses were \$2.8 million and \$3.5 million for the first quarters of 2012 and 2011, respectively.

Severance and Other Taxes. These expenses decreased \$0.4 million, or 3%, from first quarter of 2011 levels. Severance and other taxes, as a percentage of oil and gas sales, were approximately 9.5% and 9.2% in the first quarters of 2012 and 2011, respectively, due to a higher percentage of our revenues coming from oil production.

Interest. Our gross interest cost in the first quarter of 2012 was \$15.5 million, of which \$2.0 million was capitalized. Our gross interest cost in the first quarter of 2011 was \$10.3 million, of which \$1.9 million was capitalized. The increase in interest came from our new senior notes due 2022, which were issued in November 2011.

Income Taxes. Our effective income tax rate was 39.3% and 37.7% for the first quarters of 2012 and 2011, 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 2005, 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 for the provision for state income taxes (computed net of the offsetting federal benefit) and non-deductible equity compensation.

Net Income. Our first quarter 2012 net income of \$3.6 million decreased in comparison to our first quarter 2011 net income of \$20.2 million.

Liquidity and Capital Resources

Net Cash Provided by Operating Activities. For the first quarter of 2012, our net cash provided by operating activities was \$63.8 million, representing a 3% increase as compared to \$61.7 million generated during the same period of

2011. The \$2.1 million change was mainly due to working capital changes.

Existing Credit Facility. Our \$500 million credit facility with a syndicate of ten banks extends through May 12, 2016. At March 31, 2012, our borrowing base was \$325 million and our commitment amount was \$300 million. In May 2012, we increased our borrowing base to \$375 million and we elected to keep our commitment amount at \$300 million. We had no amounts drawn under our credit facility as of March 31, 2012 and, as such, had \$300 million of borrowing capacity. Our available borrowings under our 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.

2011 Debt Issuance. We issued \$250.0 million of 7-7/8% senior notes due 2022 in November 2011 at 99.156% of face value. The proceeds from this debt issuance were recorded in “Cash and cash equivalents” on the accompanying condensed consolidated balance sheet at December 31, 2011 and will be used to fund capital expenditures in 2012.

Financial Ratios

Working Capital and Debt to Capitalization Ratio. Our working capital decreased from a surplus of \$116.4 million at December 31, 2011, to a surplus of \$7.3 million at March 31, 2012. The change primarily resulted from a decrease in cash and cash equivalents as we used cash received from our debt offering in November 2011 to fund ongoing operations including our 2012 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. Not included in our working capital ratio is available liquidity through our credit facility of \$300 million. Our debt to capitalization ratio was 42% at March 31, 2012 and December 31, 2011.

Contractual Commitments and Obligations

We had no material changes in our contractual commitments and obligations from December 31, 2011 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, 2011.

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 the preceding 12-months' average price based on closing prices on the first day of each month, adjusted for price differentials and the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). We did not have any outstanding derivative instruments at March 31, 2012 that would 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 the prices used in the Ceiling Test, even if only for a short period, it is reasonably possible that non-cash write-downs of oil and gas properties would 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 would occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties if a decrease in oil and/or natural gas prices were to occur.

New Accounting Pronouncements. There are no material new accounting pronouncements that have been issued but not yet adopted as of March 31, 2012.

Forward-Looking Statements

This report includes forward-looking statements intended to qualify for the safe harbors from liability established by the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated production levels, reserve increases, capital expenditures, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words "could," "believe," "anticipate," "intend," "estimate," "budgeted", "expect," "may," "continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- technology;
- cash flows and liquidity;
- financial strategy, budget, projections and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future development costs;
- availability and terms of capital;
- drilling of wells;
- marketing and transportation of oil and natural gas;
- exploitation or property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry;
- effectiveness of our risk management activities;
- environmental liabilities;
- counterparty credit risk;
- governmental regulation and taxation of the oil and natural gas industry;
- developments in world oil markets and in oil and natural gas-producing countries;
- uncertainty regarding our future operating results;
- estimated future net reserves and present value thereof; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date they are made. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under "Risk factors" in Item 1A of our annual report on Form 10-K for the year ended December 31, 2011. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

All subsequent written and oral forward-looking statements attributable to us or to persons acting on our behalf are expressly qualified in their entirety by the foregoing. We undertake no obligation to publicly release the results of any revisions to any such forward-looking statements that may be made to reflect events or circumstances after the date of this report or to reflect the occurrence of unanticipated events.

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. This pricing volatility has continued with declining natural gas prices while oil prices have seen 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.

Price Floors – At March 31, 2012, we had oil prices floor in effect that cover total production of 270,500 barrels of oil for April and May 2012 with the strike prices ranging from \$100.00 to \$105.00.

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, 2020 and 2022 have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At March 31, 2012, 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 future cash flows.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

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

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the first three months of 2012 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 2011 Annual Report on Form 10-K.

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

The following table summarizes repurchases of our common stock occurring during the first quarter of 2012:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
01/01/12 – 01/31/12 (1)	---	\$ ---	---	\$ ---
02/01/12 – 02/29/12 (1)	78,395	\$ 33.49	---	---
03/01/12 – 03/31/12 (1)	363	\$ 29.42	---	---
Total	78,758	\$ 33.47	---	\$ ---
(1) These shares were withheld from employees to satisfy tax obligations arising upon the vesting of restricted shares.				

Item 3. Defaults Upon Senior Securities.

None.

Item 5. Other Information.

None.

Item 6. Exhibits.

4.1

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Amendment No.3, effective March 1, to the Rights Agreement, dated as of August 1, 1997, as amended and restated on March 31, 1999, and further amended as of December 12, 2005 and December 21, 2006, by and between Swift Energy Company and American Stock Transfer and Trust Company. (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed March 5, 2011, File No. 1-08754).

- 10.1 Revised Amendment No. 5 to the Swift Energy Company First Amended and Restated 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May 2, 2012, 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.
- 99.1* Amendment No. 6 to the Swift Energy Company First Amended and Restated 2005 Stock Compensation Plan.

*Filed herewith

SIGNATURES

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

SWIFT ENERGY COMPANY
(Registrant)

Date: May 3, 2012

By:

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

Date: May 3, 2012

By:

/s/ Barry S. Turcotte
Barry S. Turcotte
Vice President, Controller and Principal
Accounting Officer

Exhibit Index

- 4.1 Amendment No.3, effective March 1, to the Rights Agreement, dated as of August 1, 1997, as amended and restated on March 31, 1999, and further amended as of December 12, 2005 and December 21, 2006, by and between Swift Energy Company and American Stock Transfer and Trust Company. (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed March 5, 2011, File No. 1-08754).
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