SWIFT ENERGY CO
Form 10-Q
August 01, 2013

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

FORM 10-Q

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

For the quarterly period ended June 30, 2013
Commission File Number 1-8754
SWIFT ENERGY COMPANY
(Exact Name of Registrant as Specified in Its Charter)

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act.
Large accelerated filer þ Accelerated filer o Non-accelerated filer o Smaller reporting company o

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

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

Common Stock ($.01 Par Value) (Class of Stock)	43,382,961 Shares (Outstanding at July 31, 2013)

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SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2013
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Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries (in thousands, except share amounts)

	June 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$11,338	$170
Accounts receivable	64,517	67,318
Deferred tax asset	2,815	5,679
Other current assets	10,169	7,370
Total Current Assets	88,839	80,537
Property and Equipment:		
Property and Equipment, including $93,990 and $92,579 of unproved property costs not being amortized, respectively	5,491,252	5,192,793
Less – Accumulated depreciation, depletion, and amortization	(2,968,161)	(2,847,773)
Property and Equipment, Net	2,523,091	2,345,020
Other Long-Term Assets	17,988	18,504
Total Assets	$2,629,918	$2,444,061
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$88,419	$75,378
Accrued capital costs	104,791	73,190
Accrued interest	21,438	21,362
Undistributed oil and gas revenues	8,634	7,550
Total Current Liabilities	223,282	177,480
Long-Term Debt	1,037,435	916,934
Deferred Tax Liabilities	230,617	223,243
Asset Retirement Obligation	68,832	79,643
Other Long-Term Liabilities	10,162	9,901
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, 43,889,545 and 43,450,367 shares issued, and 43,382,709 and 42,930,071 shares outstanding, respectively	439	435
Additional paid-in capital	755,303	747,868
Treasury stock held, at cost, 506,836, and 520,296 shares, respectively	(12,495)	(13,855)
Retained earnings	316,343	302,412
Total Stockholders’ Equity	1,059,590	1,036,860
Total Liabilities and Stockholders’ Equity	$2,629,918	$2,444,061

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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues:				
Oil and gas sales	$140,892	$131,980	$287,369	$268,122
Price-risk management and other, net	1,574	2,777	1,334	2,513
Total Revenues	142,466	134,757	288,703	270,635
Costs and Expenses:				
General and administrative, net	11,191	12,190	23,916	24,073
Depreciation, depletion, and amortization	59,458	61,288	119,578	122,651
Accretion of asset retirement obligation	1,479	1,162	3,254	2,274
Lease operating cost	26,957	24,762	54,381	49,381
Transportation and gas processing	4,865	4,721	10,895	9,315
Severance and other taxes	10,501	12,200	20,276	25,160
Interest expense, net	17,000	13,319	33,802	26,784
Total Costs and Expenses	131,451	129,642	266,102	259,638
Income Before Income Taxes	11,015	5,115	22,601	10,997
Provision for Income Taxes	4,293	2,087	8,670	4,399
Net Income	$6,722	$3,028	$13,931	$6,598
Per Share Amounts-				
Basic: Net Income	$0.15	$0.07	$0.32	$0.15
Diluted: Net Income	$0.15	$0.07	$0.32	$0.15
Weighted Average Shares Outstanding - Basic	43,369	42,862	43,268	42,768
Weighted Average Shares Outstanding - Diluted	43,612	43,111	43,599	43,133

See accompanying Notes to Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net Income:	$6,722	$3,028	$13,931	$6,598
Other Comprehensive Income:				
Unrealized gains related to price risk management transactions, before taxes	—	958	—	1,171
Provision for income taxes	—	349	—	426
Unrealized gains related to price risk management transactions, net of taxes	—	609	—	745
Less: reclassification of gains on price risk management transactions to net income, before taxes	—	(1,369)	—	(1,171)
Provision for income taxes	—	(498)	—	(426)
Reclassification of gains on price risk management transactions to net income, net of taxes	—	(871)	—	(745)
Other comprehensive loss, before income taxes	—	(411)	—	—
Benefit for income taxes	—	(150)	—	—
Other comprehensive loss, net of taxes	—	(261)	—	—
Comprehensive Income	$6,722	$2,767	$13,931	$6,598

See accompanying Notes to Condensed Consolidated Financial Statements.

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

	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total
Balance, December 31, 2011	$430	$726,956	$(12,350)	$281,473	$996,509
Stock issued for benefit plans (50,987 shares)	—	354	1,300	—	1,654
Stock options exercised (63,040 shares)	1	635	—	—	636
Purchase of treasury shares (86,812 shares)	—	—	(2,805)	—	(2,805)
Tax benefits from share-based compensation	—	175	—	—	175
Employee stock purchase plan (42,624 shares)	—	1,076	—	—	1,076
Issuance of restricted stock (375,157 shares)	4	(4)	—	—	—
Amortization of share-based compensation	—	18,676	—	—	18,676
Net Income	—	—	—	20,939	20,939
Balance, December 31, 2012	$435	$747,868	$(13,855)	$302,412	$1,036,860
Stock issued for benefit plans (104,890 shares) (1)	—	(1,171)	2,793	—	1,622
Purchase of treasury shares (91,430 shares) (1)	—	—	(1,433)	—	(1,433)
Tax benefits from share-based compensation (1)	—	(1,568)	—	—	(1,568)
Employee stock purchase plan (72,273 shares) (1)	1	945	—	—	946
Issuance of restricted stock (366,905 shares) (1)	3	(3)	—	—	—
Amortization of share-based compensation (1)	—	9,232	—	—	9,232
Net Income (1)	—	—	—	13,931	13,931
Balance, June 30, 2013 (1)	$439	$755,303	$(12,495)	$316,343	$1,059,590

(1) 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)

	Six Months Ended June 30,	
	2013	2012
Cash Flows from Operating Activities:		
Net income	$13,931	$6,598
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion, and amortization	119,578	122,651
Accretion of asset retirement obligation	3,254	2,274
Deferred income taxes	8,670	4,399
Share-based compensation expense	6,018	7,181
Other	(6,024)	(1,277)
Change in assets and liabilities-		
Decrease in accounts receivable	601	12,501
Increase (decrease) in accounts payable and accrued liabilities	3,605	(3,313)
Decrease in income taxes payable	(178)	(198)
Increase in accrued interest	76	4,863
Net Cash Provided by Operating Activities	149,531	155,679
Cash Flows from Investing Activities:		
Additions to property and equipment	(265,317)	(374,753)
Proceeds from the sale of property and equipment	6,841	284
Net Cash Used in Investing Activities	(258,476)	(374,469)
Cash Flows from Financing Activities:		
Net proceeds from bank borrowings	120,600	—
Net proceeds from issuances of common stock	946	1,451
Purchase of treasury shares	(1,433)	(2,686)
Net Cash Provided by (Used in) Financing Activities	120,113	(1,235)
Net increase (decrease) in Cash and Cash Equivalents	11,168	(220,025)
Cash and Cash Equivalents at Beginning of Period	170	251,696
Cash and Cash Equivalents at End of Period	$11,338	$31,671
Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	$32,708	$20,698
Cash paid during period for income taxes	$178	$198

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, 2012 as filed with the Securities and Exchange Commission.

(2) Summary of Significant Accounting Policies

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

Subsequent Events. We have evaluated subsequent events of our 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 amounts of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates and assumptions underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- estimates related to the collectability of accounts receivable and the credit worthiness of our customers,
- estimates of the counterparty bank risk related to letters of credit that our customers may have issued on our behalf,
- estimates of future costs to develop and produce reserves,
- accruals related to oil and gas sales, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage, and the solvency of insurance providers,
- estimates in the calculation of share-based compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,
- the estimated future cost and timing of asset retirement obligations,
- estimates made in our income tax calculations,
- estimates in the calculation of the fair value of hedging assets, and
- estimates in the assessment of current litigation claims against the company.

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.

We are subject to legal proceedings, claims, liabilities and environmental matters that arise in the ordinary course of business. We accrue for losses when such losses are considered probable and the amounts can be reasonably estimated.

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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 June 30, 2013 and 2012 such internal costs capitalized totaled $7.5 million and $7.8 million, respectively. For the six months ended June 30, 2013 and 2012, such internal costs capitalized totaled $16.0 million and $16.2 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the three months ended June 30, 2013 and 2012, capitalized interest on unproved properties totaled $1.9 million and $2.0 million, respectively. For the six months ended June 30, 2013 and 2012, capitalized interest on unproved properties totaled $3.8 million and $4.0 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

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

(in thousands)	June 30, 2013	December 31, 2012
Property and Equipment		
Proved oil and gas properties	$5,354,887	$5,058,524
Unproved oil and gas properties	93,990	92,579
Furniture, fixtures, and other equipment	42,375	41,690
Less – Accumulated depreciation, depletion, and amortization	(2,968,161)	(2,847,773)
Property and Equipment, Net	$2,523,091	$2,345,020

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 two and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

Geological and geophysical ("G&G") costs incurred on developed properties are recorded in "Proved properties" and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in “Unproved properties” and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is assessed quarterly, on a 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.

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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, discounted at 10% , and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). This calculation is done on a country-by-country basis.

The calculations of the Ceiling Test and provision for DD&A are 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 reduces 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 June 30, 2013 and December 31, 2012, we did not have any material natural gas imbalances.

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

Accounts Receivable. We assess the collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At June 30, 2013 and December 31, 2012, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balance on the accompanying condensed consolidated balance sheets.

At June 30, 2013, our "Accounts receivable" balance included $48.0 million for oil and gas sales, $2.6 million for joint interest owners and $14.0 million for other receivables. At December 31, 2012, our "Accounts receivable" balance included $53.9 million for oil and gas sales, $3.6 million for joint interest owners and $9.8 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 7.125% senior notes due in 2017 mature on June 1, 2017, and the balance of their issuance costs at June 30, 2013, was $2.0 million. The 8.875% senior notes due in 2020 mature on January 15, 2020, and the balance of their issuance costs at June 30, 2013, was $3.8 million. The 7.875% senior notes due in 2022 mature on March 1, 2022, and the balance of their issuance costs at June 30, 2013, was $6.8 million. The balance of revolving credit facility issuance costs at June 30, 2013, was $3.8 million.

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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.

Prior to January 1, 2013, the Company had elected hedge accounting on all qualifying derivative instruments. As of December 31, 2012, the Company did not have any outstanding derivatives. For all derivatives entered into after January 1, 2013, the Company elected not to apply hedge accounting. The changes in the fair value of our derivatives initiated after January 1, 2013 are recognized in "Price-risk management and other, net” on the accompanying condensed consolidated statements of operations.

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. Prior to January 1, 2013, all hedges 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 was highly effective and was designated, documented and qualified as a cash flow hedge, to the extent that the hedge was effective, were recorded in “Accumulated other comprehensive income, net of income tax” on the accompanying condensed consolidated balance sheets. When the hedged transactions were recorded upon the actual sale of the oil and natural gas, those gains or losses were reclassified from “Accumulated other comprehensive income, net of income tax” and were recorded in “Price-risk management and other, net” on the accompanying condensed consolidated statements of operations. Changes in the fair value of derivatives that did not meet the criteria for hedge accounting, and the ineffective portion of the hedge for which hedge accounting was elected, was recognized in "Price-risk management and other, net."

During the three months ended June 30, 2013 and 2012, we recognized a net gain of $1.5 million and a net gain of $2.6 million, respectively, relating to our derivative activities. During the six months ended June 30, 2013 and 2012, we recognized a net gain of $1.2 million and a net gain of $2.3 million, respectively, relating to our derivative activities. We also recorded an unrealized gain of $1.8 million for the three and six months ended June 30, 2013. This activity is recorded in “Price-risk management and other, net” on the accompanying condensed consolidated statements of operations. Had these amounts been recognized in the oil and gas sales account they would not have materially changed our per unit sales prices received. The ineffectiveness for the three and six months ended June 30, 2012, was not material. The effects of our derivatives are included in the "Other" section of our operating activities on the accompanying condensed consolidated statements of cash flows.

The fair values of our derivatives are computed using using commonly accepted industry-standard models and are periodically verified against quotes from brokers. The fair value of these instruments at June 30, 2013 was $2.1 million which was recognized on the accompanying condensed consolidated balance sheet in “Other current assets.” At June 30, 2013, we also had $0.2 million in receivables for settled derivatives which were recognized on the accompanying balance sheet in “Accounts receivable” and were subsequently collected in July 2013.

At June 30, 2013, we had natural gas price floors in effect that covered natural gas production of 1,240,000 MMBtu from August 2013 through September 2013 with a strike price of $3.95 per MMBtu. We also had natural gas collars in effect that covered natural gas production of 3,010,000 MMBtu from August 2013 through December 2013 with a floor price of $3.75 per MMBtu and a weighted average call price of $5.05 per MMBtu. In addition, we had natural gas participating collars in effect that covered natural gas production of 1,800,000 MMBtu from October 2013 through December 2013 with a floor price of $4.00 per MMBtu and call prices of $5.00 per MMBtu and $6.00 per MMBtu.

At June 30, 2013, we had oil participating collars in effect that covered oil production of 201,000 barrels from July 2013 through September 2013 with a floor price of $90.00 per barrel and call prices of $100.00 per barrel and $108.00 per barrel.

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees are recorded as a reduction to “General and administrative, net” on the accompanying condensed consolidated statements of operations. Our supervision fees are based on COPAS industry guidelines. The amount of supervision fees charged for the three and six months ended June 30, 2013 and 2012 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated was $3.3 million and $2.9 million in the three months ended June 30, 2013 and 2012, respectively. The total amount of supervision fees charged to the wells we operated was $6.1 million and $5.8 million in the six months ended June 30, 2013 and 2012, respectively.

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Inventories. Inventories consist primarily of tubulars and other equipment and supplies 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 $2.8 million and $5.6 million at June 30, 2013 and December 31, 2012, respectively.

Income Taxes. Under guidance contained in FASB ASC 740-10, deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws.

We follow the recognition and disclosure provisions under guidance contained in FASB ASC 740-10-25. Under this guidance, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. Our policy is to record interest and penalties relating to uncertain tax positions in income tax expense. At June 30, 2013, we did not have any accrued liability for uncertain tax positions.

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

Our U.S. Federal income tax returns for 2007 forward (except for 2008 which was closed through the IRS audit process), our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2005, and our Texas franchise tax returns after 2007 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 (in thousands):

	June 30, 2013	December 31, 2012
Trade accounts payable (1)	$41,145	$31,128
Accrued operating expenses	17,970	14,647
Accrued payroll costs	8,238	12,297
Asset retirement obligation – current portion	9,520	7,134
Accrued taxes	8,652	5,373
Other payables	2,894	4,799
Total accounts payable and accrued liabilities	$88,419	$75,378

(1) Included in “trade accounts payable” are liabilities of approximately $27.9 million and $13.3 million at June 30, 2013 and December 31, 2012, respectively, for outstanding checks.

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

Restricted Cash. These balances primarily include amounts held in escrow accounts to satisfy domestic plugging and abandonment obligations. As of June 30, 2013 and December 31, 2012, these assets were approximately $1.0 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.

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 as part of depreciation, depletion, and amortization expense for our oil and gas properties. Upon settlement of the liability, the Company 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.

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The following provides a roll-forward of our asset retirement obligation (in thousands):

	2013
Asset Retirement Obligation recorded as of January 1	$ 86,777
Accretion expense	3,254
Liabilities incurred for new wells and facilities construction	1,214
Reductions due to sold and abandoned wells and facilities	(12,780)
Revisions in estimates	(113)
Asset Retirement Obligation as of June 30,	$ 78,352

Effective May 1, 2013, we sold our Brookeland field in Texas. This sale included the buyer's assumption of our plugging and abandonment liability for which we were carrying an $11.3 million asset retirement obligation related to these properties. This decrease is shown above in “Reductions due to sold and abandoned wells and facilities.”

At June 30, 2013 and December 31, 2012, approximately $9.5 million and $7.1 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. There are no material new accounting pronouncements that have been issued but not yet adopted as of June 30, 2013.

(3) Share-Based Compensation

We have various types of share-based compensation plans. Refer to our definitive proxy statement for our annual meeting of shareholders filed with the SEC on April 5, 2013, as well as Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2012, 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 stock options are exercised, generally for the excess of the market value on the exercise date over the exercise price of the stock option awards. We receive an additional tax deduction when restricted stock awards vest 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 and six months ended June 30, 2013 and 2012, we did not recognize any material excess tax benefit or shortfall in earnings.

There were no stock option exercises for the six months ended June 30, 2013. Net cash proceeds from the exercise of stock options was $0.4 million for the six months ended June 30, 2012. The actual income tax benefit from stock option exercises was $0.2 million for the six months ended June 30, 2012.

Share-based compensation expense for awards issued to both employees and non-employees, which was recorded in “General and administrative, net” in the accompanying condensed consolidated statements of operations, was $2.8 million and $3.3 million for the three months ended June 30, 2013 and 2012, respectively, and was $5.6 million and $6.7 million for the six months ended June 30, 2013 and 2012, respectively. Share-based compensation recorded in lease operating cost was $0.1 million for the three months ended June 30, 2013 and 2012 and was $0.2 million for six months ended June 30, 2013 and 2012. We also capitalized $1.6 million and $1.5 million of share-based compensation for the three months ended June 30, 2013 and 2012, respectively, and capitalized $3.2 million and $2.9 million for the six months ended June 30, 2013 and 2012, respectively. We view stock option awards and restricted stock awards with graded vesting as single awards with an expected life equal to the average expected life of component awards and amortize the awards on a straight-line basis over the life of the awards.

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Stock Option Awards

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 stock option awards issued during the indicated periods:

	Six Months Ended June 30, 2012	
Dividend yield	0	%
Expected volatility	61.2	%
Risk-free interest rate	0.8	%
Expected life of stock option awards (in years)	4.3	
Weighted-average grant-date fair value	$ 15.71	

During the first six months of 2013 we did not grant any stock option awards. 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 stock option grants.

At June 30, 2013, we had $1.5 million of unrecognized compensation cost related to stock option awards, which is expected to be recognized over a weighted-average period of one year. The following table represents stock option award activity for the six months ended June 30, 2013:

	Shares	Wtd. Avg. Exercise Price
Options outstanding, beginning of period	1,585,594	$ 33.13
Options granted	—	$ —
Options canceled	(23,026)	$ 44.90
Options exercised	—	$ —
Options outstanding, end of period	1,562,568	$ 32.96
Options exercisable, end of period	1,276,225	$ 32.44

Our stock option awards outstanding and exercisable at June 30, 2013 were out of the money and therefore had no aggregate intrinsic value. The weighted average contract life of stock option awards outstanding and exercisable at June 30, 2013 was 5.6 years and 4.9 years, respectively. There were no stock option exercises for the six months ended June 30, 2013 while the total intrinsic value of stock options exercised during the six months ended June 30, 2012 was $0.7 million.

Restricted Stock Awards

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, 2012, allow for the issuance of restricted stock awards that may not be sold or otherwise transferred until certain restrictions have lapsed. The unrecognized compensation cost related to these awards is expected to be expensed over the period the restrictions lapse (generally one to three years).

The compensation expense for these awards was determined based on the closing market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of June 30, 2013, we had unrecognized compensation expense of $17.6 million related to restricted stock awards which is expected to be recognized over a weighted-average period of 1.8 years. The grant date fair value of shares vested during the six months ended June 30, 2013 was $12.1 million.

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The following table represents restricted stock award activity for the six months ended June 30, 2013:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	896,164	$ 33.38
Restricted shares granted	630,930	$ 15.36
Restricted shares canceled	(16,271)	$ 24.68
Restricted shares vested	(366,905)	$ 32.85
Restricted shares outstanding, end of period	1,143,918	$ 23.74

Performance-Based Restricted Stock Units

In 2013, our executive compensation program was modified and, for the first time, performance-based restricted stock units were granted containing pre-determined market and performance conditions with a cliff vesting period of 3.1 years. We granted 189,700 of these units at a 100% of target payout while the conditions of the grants allow for a payout ranging between no payout and 200% of target.

The compensation expense for the market condition is based on a grant date valuation of $14.85 per unit using a Monte-Carlo simulation. The unrecognized compensation expense related to these shares is approximately $1.8 million as of June 30, 2013 and is expected to be recognized over the next 2.8 years. The performance condition is remeasured quarterly and compensation expense is recorded based on the closing market price of our stock on the date of grant ($15.47 per unit) per unit multiplied by the expected payout level. The payout level is calculated based on actual performance achieved during the performance period compared to a defined peer group. The unrecognized compensation expense related to these shares, based on the current estimated payout level achieved for the performance period, is approximately $0.7 million as of June 30, 2013 and is expected to be recognized over the next 2.8 years.

(4) Earnings Per Share

The Company computes earnings per share in accordance with FASB ASC 260-10. Basic earnings per share (“Basic EPS”) has been computed using the weighted average number of common shares outstanding during each period. Diluted EPS assumes, as of the beginning of the period, exercise of stock options and restricted stock grants using the treasury stock method. Diluted EPS also assumes conversion of performance-based restricted stock units to common shares based on the number of shares (if any) that would be issuable, according to predetermined performance and market goals, if the end of the reporting period was the end of the performance period. Certain of our stock options and restricted stock grants that would potentially dilute Basic EPS in the future were also antidilutive for the three and six month periods ended June 30, 2013 and 2012, and are discussed below.

Due to recently approved amendments to our stock plan agreement, which clarify that unvested shares or unvested units are not dividend eligible, our earnings per share calculations, including historical periods, have been presented based on the traditional earnings per share calculation methodology instead of the two-class methodology. The effects of this change were immaterial for all historical periods presented.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the three and six months ended June 30, 2013 and 2012 (in thousands, except per share amounts):

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	Three Months Ended June 30, 2013			Three Months Ended June 30, 2012		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$6,722	43,369	$0.15	$3,028	42,862	$0.07
Dilutive Securities:						
Stock Options		—			92	
Restricted Stock Awards		192			157	
Restricted Stock Units		51			—	
Diluted EPS:						
Net Income and Assumed Share Conversions	$6,722	43,612	$0.15	$3,028	43,111	$0.07

	Six Months Ended June 30, 2013			Six Months Ended June 30, 2012		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$13,931	43,268	$0.32	$6,598	42,768	$0.15
Dilutive Securities:						
Stock Options		2			158	
Restricted Stock Awards		242			207	
Restricted Stock Units		87			—	
Diluted EPS:						
Net Income and Assumed Share Conversions	$13,931	43,599	$0.32	$6,598	43,133	$0.15

Approximately 1.6 million and 1.3 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months ended June 30, 2013 and 2012, respectively, and approximately 1.5 million and 1.0 million stock options to purchase shares were not included in the computation of Diluted EPS for the six months ended June 30, 2013 and 2012, respectively, because these stock options were antidilutive. Approximately 0.3 million and 0.5 million restricted stock awards were not included in the computation of Diluted EPS for the three months ended June 30, 2013 and 2012, respectively, and approximately 0.3 million and 0.4 million restricted stock awards were not included in the computation of Diluted EPS for the six months ended June 30, 2013 and 2012, respectively, because they were antidilutive. Approximately 0.3 million shares related to performance-based restricted stock units that could be converted to common shares based on predetermined performance and market goals were not included in the computation of Diluted EPS for the three and six months ended June 30, 2013, because the performance and market conditions had not been met, assuming the end of the reporting period was the end of the performance period.

(5) Long-Term Debt

Our long-term debt as of June 30, 2013 and December 31, 2012, was as follows (in thousands):

	June 30, 2013	December 31, 2012
7.125% senior notes due in 2017	$250,000	$250,000
8.875% senior notes due in 2020 (1)	222,293	222,147
7.875% senior notes due in 2022 (1)	405,142	405,387
Bank Borrowings due in 2017	160,000	39,400
Long-Term Debt (1)	$1,037,435	$916,934

(1) Amounts are shown net of any debt discount or premium

As of June 30, 2013, our bank borrowings of $160.0 million are due in 2017. The maturities on our senior notes are $250.0 million in 2017, $225.0 million in 2020 and $400.0 million in 2022.

We have capitalized interest on our unproved properties in the amount of $1.9 million and $2.0 million for the three months ended June 30, 2013 and 2012, respectively, and we have capitalized interest on our unproved properties in the amount of $3.8 million and $4.0 million for the six months ended June 30, 2013 and 2012 respectively.

Bank Borrowings. Effective April 26, 2013, we renewed the maturity of our $500.0 million credit facility with a syndicate of 11 banks through November 1, 2017. The borrowing base and commitment amount of $450.0 million remained unchanged.

We had $160.0 million and $39.4 million in outstanding borrowings under our credit facility at June 30, 2013 and December 31, 2012, respectively. The interest rate on our credit facility is either (a) the lead bank's prime rate plus an applicable margin or (b) the 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 0.5%, 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. At June 30, 2013, the lead bank's prime rate was 3.25% and the commitment fee associated with the credit facility was 0.375%.

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 as defined in the terms of our credit facility) and limitations on incurring other debt. Since inception, no cash dividends have been declared on our common stock. As of June 30, 2013, 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, the commitment amount can be less than or equal 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 $1.2 million and $0.6 million for the three months ended June 30, 2013 and 2012, respectively. Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $2.4 million and $1.2 million for the six months ended June 30, 2013 and 2012, respectively. The amount of commitment fees included in interest expense, net was $0.3 million and $0.4 million for the three months ended June 30, 2013 and 2012, respectively, and $0.6 million and $0.7 million for the six months ended June 30, 2013 and 2012.

Senior Notes Due In 2022. These notes consist of $400.0 million of 7.875% senior notes that will mature on March 1, 2022. On November 30, 2011, we issued $250.0 million of these senior notes at a discount of $2.1 million or 99.156% of par, which equates to an effective yield to maturity of 8%. The original discount of $2.1 million is recorded in "Long-Term Debt" on our consolidated balance sheets and will be amortized over the life of the notes using the effective interest method. On October 3, 2012, we issued an additional $150.0 million of these senior notes at 105% of par, which equates to a yield to worst of 6.993%. The premium of $7.5 million is recorded in "Long-Term Debt" on our consolidated balance sheets and will be amortized over the life of the notes using the effective interest method. 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 $7.5 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, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates, consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of June 30, 2013.

Interest expense on the senior notes due in 2022, including amortization of debt issuance costs and debt premium, totaled $7.9 million and $5.0 million for the three months ended June 30, 2013 and 2012, respectively, and $15.8 million and $10.1 million for the six months ended June 30, 2013 and 2012.

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Senior Notes Due In 2020. These notes consist of $225.0 million of 8.875% senior notes issued at 98.389% of par, which equates to an effective yield to maturity of 9.125%. The notes were issued on November 25, 2009 with an original discount of $3.6 million and will mature on January 15, 2020. The original discount of $3.6 million is recorded in "Long-Term Debt" on our condensed consolidated balance sheets and will be amortized over the life of the notes using the effective interest method. 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. 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, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates, consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of June 30, 2013.

Interest expense on the senior notes due in 2020, including amortization of debt issuance costs and debt discount, totaled $5.2 million for the three months ended June 30, 2013 and 2012, respectively, and $10.3 million for the six months ended June 30, 2013 and 2012.

Senior Notes Due In 2017. These notes consist of $250.0 million of 7.125% senior notes due in 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. We may redeem some or all of these notes, with certain restrictions, starting at a redemption price of 102.375% of the principal, plus accrued and unpaid interest, declining in twelve-month intervals to 100% on June 1, 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, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates, consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of June 30, 2013.

Interest expense on the senior notes due in 2017, including amortization of debt issuance costs, totaled $4.6 million for the three months ended June 30, 2013 and 2012, as well as $9.1 million for the six months ended June 30, 2013 and 2012.

(6) Acquisitions and Dispositions

Effective May 1, 2013, we disposed of our Brookeland field in Texas and received net cash proceeds of $5.8 million. This disposition also included the buyer's assumption of our plugging and abandonment liability that was previously included as $11.3 million in "Asset Retirement Obligation" on the accompanying condensed consolidated balance sheets.

(7) 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.

Based upon quoted market prices as of June 30, 2013 and December 31, 2012, the fair value and carrying value of our senior notes was as follows (in millions):

	June 30, 2013		December 31, 2012	
	Fair Value	Carrying Value	Fair Value	Carrying Value
7.125% senior notes due in 2017	$256.3	$250.0	$258.1	$250.0
8.875% senior notes due in 2020	$232.9	$222.3	$244.4	$222.1
7.875% senior notes due in 2022	$400.0	$405.1	$424.0	$405.4

Our senior notes due in 2017, 2020 and 2022 are stated at carrying value on our financial statements, net of any discount or premium. If we recorded these notes at fair value they would be level 1 in our fair value hierarchy as they are traded in an active market with quoted prices for identical instruments.

The following table presents our assets that are measured at fair value as of June 30, 2013, and are categorized using the fair value hierarchy. At December 31, 2012, the Company did not have any derivative instruments. 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 Assets (Liabilities)	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
June 30, 2013				
Natural Gas Derivatives	$2.1	$—	$2.1	$—

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

Level 1 – Uses quoted prices in active markets for identical, unrestricted assets or liabilities. Instruments in this category have comparable fair values for identical instruments in active markets.

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 are periodically verified against quotes from brokers and include our commodity derivatives that we value using commonly accepted industry-standard models 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.

(8) Condensed Consolidating Financial Information

Swift Energy Company (the parent) is the issuer and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) is the sole guarantor of our senior notes due in 2017, 2020 and 2022. Swift Energy Company does not have any independent assets or operations. The guarantees on our senior notes due in 2017, 2020 and 2022 are full and unconditional. All subsidiaries of Swift Energy Company, other than Swift Energy Operating, LLC, are minor.

(9) Commitments and Contingencies

In May 2013, the Company entered into a new 12.5 year lease agreement for office space in Houston, Texas under the terms of an operating lease, with the lease commencing on or after March 1, 2015, and with minimum contractual obligations of approximately $104 million in the aggregate. We will amortize the total payments required under the lease agreement on a straight-line basis over the term of the lease.

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We had no other material changes in our contractual commitments and obligations from the amounts referenced under Note 5 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2012.

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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, 2012 and 2011. 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 33% of our second quarter 2013 production and 67% of our oil and gas sales, and combined production of both oil and natural gas liquids ("NGLs") constituted 53% of our second quarter 2013 production and 78% of our oil and gas sales. In recent periods, this has allowed us to benefit from better margins for oil production, as oil prices are significantly higher on a Boe basis than natural gas prices.

Second Quarter 2013 Activities

- Production: Our production volumes decreased by 5% in the second quarter of 2013 when compared to volumes in the same period in 2012 as oil volumes increased by 1%, NGL volumes increased by 28% and natural gas production volumes decreased by 17%. The increase in NGL volumes and decrease in natural gas volumes when compared to the second quarter of 2012 were primarily from our South Texas area. Sequentially, production volumes decreased by 1% in the second quarter of 2013 compared to first quarter of 2013 levels as oil volumes decreased by 8%, NGL volumes decreased by 1% and natural gas production volumes increased by 3%. The decrease in oil production when compared to the first quarter of 2013 was primarily from our South Texas area.
- Pricing: Driven primarily by higher gas prices, our weighted average sales price in the second quarter of 2013 increased by 12% when compared to levels in the second quarter of 2012 and decreased by 2% from the first quarter of 2013. When compared to the second quarter of 2012, oil prices decreased 5%, NGL prices decreased 16% and natural gas prices increased 93%. When compared to the first quarter of 2013, oil prices decreased 5%, NGL prices decreased 1% and natural gas prices increased 30%.
- Cash provided by operating activities: For the first six months of 2013, our cash provided by operating activities decreased by $6.1 million or 4%, when compared to the first six months of 2012, due primarily to higher positive working capital adjustments in the 2012 period. In the second quarter of 2013, our cash provided by operating activities increased by $25.1 million or 40%, when compared to the first quarter of 2013, due primarily to higher positive changes in working capital during the second quarter of 2013.
- Available liquidity: We currently have $160.0 million in outstanding borrowings under our credit facility. Our borrowing base and commitment amount under the credit facility is $450.0 million which provides us with approximately $290 million of liquidity at June 30, 2013.
- 2013 capital expenditures: Our capital expenditures on a cash flow basis were $265.3 million in the first six months of 2013, compared to $374.8 million in the first six months of 2012. The expenditures were mainly due to drilling and completion activity for the first six months of 2013 in our South Texas core region as we drilled 11 wells in our Artesia Wells Eagle Ford field, five wells in our AWP Eagle Ford field, three wells in our AWP Olmos field and two wells in our Fasken field, which helped us evaluate and maintain our acreage positions in those areas. In Southeast Louisiana we drilled two wells at Lake Washington, one of which was a dry hole and in Central Louisiana we drilled one non-operated well in our Burr Ferry field and one operated well in our South Bearhead Creek field. These expenditures were funded by $149.5 million of cash provided by operating activities and borrowings under our credit

facility.

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Strategy and Outlook

- Accelerating our activity in South Texas with expanded capital budget: We have committed to accelerating our activity in South Texas during the second half of 2013 and now expect two drilling rigs to remain active and maintain the momentum we've established established in the area. We now plan to spend a company total of between $500 to $525 million in 2013 on capital activities which will be funded through internally generated cash flows and our credit facility.
- Improved performance of Eagle Ford shale assets: We have seen improved performance this year in both initial production rates in our Eagle Ford wells along with increases in estimated ultimate recoveries (EUR). Our goal this year is to improve initial production rates by 10% for these wells, increase EURs by 10% and reduce the average cost per well by 10%.
- Continued focus on oil and liquid-rich properties: Our inventory of drilling locations allows us to be flexible in scheduling upcoming wells in South Texas to focus on oil and natural gas liquids. Having fulfilled our near-term obligations on most of our acreage prospective for dry natural gas production, we are concentrating on our higher return, liquid-rich acreage almost exclusively in 2013. We plan to fund these expenditures through operating cash flow and availability under our credit facility.
- Operating efficiencies: Our South Texas drilling activities continued to benefit from optimized well design, improved operational efficiencies, and applied lessons learned from our experience in this area, all of which have resulted in a reduction of drilling days per well. Consequently, we are currently able to drill more wells per rig than previously expected. We have also experienced efficiency gains in our hydraulic fracturing activities which enable us to perform more frac stages per month and lower the overall frac cost per stage.
- Capital cost saving measures: We have also realized significant capital cost savings in South Texas related to pad drilling, well construction & completion re-design, sourcing & 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 2013 program execution.
- Divesting of our central Louisiana assets: We have decided to sell our Austin Chalk and Wilcox assets in Louisiana to increase our focus and build upon the operational success of our more predictable assets in South Texas. The sales of these assets are expected to occur in the next six to twelve months and should provide us with adequate capital to fund the increased activity in South Texas as we grow production and cash flows in that area.
- Strategic Growth Initiatives: We plan to drill a well to test the Niobrara oil formation in La Plata County, Colorado, with an expected spud date in the third quarter of 2013. We have also begun working with potential partners on drilling a sub-salt exploration test in our Lake Washington field. A significant amount of work remains before we are in a position to drill this prospect, but responses from potential industry partners have been well received and we believe we have cleared the first hurdle of industry peer review. In the second quarter of 2013, we drilled a well to test the Wilcox formation in our South Bearhead Creek field. This well experienced mechanical difficulties during completion activities that will limit the productivity of this well, but we have proven that horizontal drilling and multi-stage completion technology will enhance development of this acreage. With that concept proven, we believe this asset is a viable candidate for divestment and will be included in the planned asset sales in our central Louisiana area.

Known Trends and Uncertainties Affecting our Business

- Volatility of commodity prices: Several factors such as increases in shale and tight sands production, variability in weather patterns, economic conditions and other factors affecting supply & demand balances for our products has led to high volatility in product prices. In particular we have experienced depressed natural gas and natural gas liquid prices in recent periods. Lower natural gas and natural gas liquids prices equate to lower revenue and cash flows and might lead to reductions in our borrowing capacity. Lower natural gas and natural gas liquid prices in the future could lead to potential reserves reductions which could result in full-cost ceiling write-downs.
-

- 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 area, 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. In South Texas we have seen improvement in the availability of services as additional equipment has moved into this area.
- Employee retention: As our competitors expand their workforce, we must focus more attention on keeping our highly-skilled employees. There has been and continues to be constant cost pressure to retain and hire these employees, and these costs do not decline as rapidly and significantly as hydrocarbon prices.

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Results of Operations

Revenues — Three Months Ended June 30, 2013 and 2012

Our revenues in the second quarter of 2013 increased by 6% compared to revenues in the second quarter of 2012, due primarily to higher natural gas pricing and higher NGL production, partially offset by lower natural gas production as well as lower oil and NGL pricing. Average oil prices we received were 5% lower than those received during the second quarter of 2012, while natural gas prices were 93% higher, and NGL prices were 16% lower.

Crude oil production was 33% and 31% of our production volumes in the second quarters of 2013 and 2012, respectively. Crude oil sales were 67% and 74% of oil and gas sales in the second quarters of 2013 and 2012, respectively. Natural gas production was 47% and 54% of our production volumes in the second quarters of 2013 and 2012, respectively. Natural gas sales were 22% and 14% of oil and gas sales in the second quarters of 2013 and 2012, respectively. The remaining production in each period was from NGLs.

The following table provides additional information regarding our oil and gas sales, excluding any effects of our hedging activities, for the three months ended June 30, 2013 and 2012:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2013	2012	2013	2012
Southeast Louisiana	$43.8	$55.9	462	572
South Texas	85.6	63.0	2,123	2,121
Central Louisiana / East Texas	11.3	12.9	192	219
Other	0.2	0.2	1	6
Total	$140.9	$132.0	2,778	2,918

In the second quarter of 2013, our $8.9 million, or 7% increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $7.2 million favorable impact on sales, with an increase of $14.6 million attributable to the 93% increase in natural gas prices, a decrease of $3.0 million due to the 16% decrease in NGL prices and a decrease of $4.4 million due to the 5% decrease in average oil prices received.
- Volume variances that had a $1.7 million favorable impact on sales, with an $4.2 million increase attributable to the 0.1 million Bbl increase in NGL production volumes and a $0.7 million increase due to a less than 0.1 million Bbl increase in oil production volumes, partially offset by a $3.2 million decrease due to the 1.6 Bcf decrease 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 June 30, 2013 and 2012:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Three Months Ended June 30, 2013	911	549	7.9	2,778	$103.15	$29.74	$3.86
Three Months Ended June 30, 2012	905	430	9.5	2,918	$108.02	$35.25	$2.01

For the three months ended June 30, 2013 and 2012, we recorded net gains of $1.5 million and $2.6 million, respectively, related to our derivative 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 $102.84 and $110.93 for the second quarters of 2013 and 2012, respectively, and our average natural gas price would have been $4.09 and $2.01 for the second quarters of 2013 and 2012, respectively.

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Costs and Expenses — Three Months Ended June 30, 2013 and 2012

Our expenses in the second quarter of 2013 increased $1.8 million, or 1%, compared to those in the second quarter of 2012, for the reasons noted below.

Lease operating cost. These costs increased $2.2 million, or 9%, compared to the level of such expenses in the second quarter of 2012. The increase was primarily related to South Texas as we incurred higher chemical treating costs, higher compliance costs and higher surface maintenance costs, partially offset by lower salt water disposal costs. Our lease operating costs per Boe produced were $9.70 and $8.48 for the second quarters of 2013 and 2012, respectively.

Transportation and gas processing. These costs increased $0.1 million, or 3%, compared to the level of such expenses in the second quarter of 2012. Our Transportation and gas processing costs per Boe produced were $1.75 and $1.62 for the second quarters of 2013 and 2012, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses decreased $1.8 million, or 3% from those in the second quarter of 2012. The decrease was due to higher reserve volumes partially offset by a higher depletable base including higher future development costs. Our DD&A rate per Boe of production was $21.40 and $21.00 in the second quarters of 2013 and 2012, respectively.

General and Administrative Expenses, Net. These expenses decreased $1.0 million, or 8%, from the level of such expenses in the second quarter of 2012. The decrease was primarily due to a lower corporate benefit accrual and lower deferred compensation, partially offset by higher salaries and burdens as well as higher temporary labor costs. For the second quarters of 2013 and 2012, our capitalized general and administrative costs totaled $7.5 million and $7.8 million, respectively. Our net general and administrative expenses per Boe produced decreased to $4.03 per Boe in the second quarter of 2013 from $4.18 per Boe in the second quarter of 2012. The supervision fees recorded as a reduction to general and administrative expenses were $3.3 million and $2.9 million for the second quarters of 2013 and 2012.

Severance and Other Taxes. These expenses decreased $1.7 million, or 14%, from second quarter 2012 levels. Severance and other taxes, as a percentage of oil and gas sales, were approximately 7.5% and 9.2% in the second quarters of 2013 and 2012, respectively. The decrease was primarily driven by a shift in oil production to South Texas, as our Texas oil production carries a lower severance rate then our Louisiana oil production.

Interest. Our gross interest cost in the second quarter of 2013 was $18.9 million, of which $1.9 million was capitalized. Our gross interest cost in the second quarter of 2012 was $15.3 million, of which $2.0 million was capitalized. The increase came from the additional $150.0 million of senior notes due 2022 that were issued in October 2012 along with additional borrowings on our credit facility.

Income Taxes. Our effective income tax rate was 39.0% and 40.8% for the second quarters of 2013 and 2012, respectively. 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.

Revenues — Six Months Ended June 30, 2013 and 2012

Our revenues in the first six months of 2013 increased by 7% compared to revenues in the first six months of 2012, due to higher natural gas pricing as well as higher oil and NGL production, partially offset by lower natural gas production and lower NGL pricing. Average oil prices we received were 4% lower than those received during the first six months of 2012, while natural gas prices were 63% higher, and NGL prices were 25% lower.

Crude oil production was 34% and 31% of our production volumes in the six months ended June 30, 2013 and 2012, respectively. Crude oil sales were 70% and 73% of oil and gas sales in the six months ended June 30, 2013 and 2012, respectively. Natural gas production was 46% and 55% of our production volumes in the six months ended June 30, 2013 and 2012, respectively. Natural gas sales were 19% and 15% of oil and gas sales in the six months ended June 30, 2013 and 2012, respectively. The remaining production in each year was from NGLs.

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The following table provides additional information regarding our oil and gas sales, excluding any effects of our hedging activities, for the six months ended June 30, 2013 and 2012:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2013	2012	2013	2012
Southeast Louisiana	$ 87.8	$ 114.2	908	1,165
South Texas	172.2	128.7	4,228	4,142
Central Louisiana / East Texas	26.6	24.8	441	401
Other	0.8	0.4	20	9
Total	$ 287.4	$ 268.1	5,597	5,717

In the six months ended June 30, 2013, our $19.2 million, or 7% increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $1.7 million favorable impact on sales, with an increase of $20.6 million attributable to the 63% increase in natural gas prices, partially offset by a decrease of $11.2 million due to the 25% decrease in NGL prices and a decrease of $7.7 million due to the 4% decrease in average oil prices received.
- Volume variances that had a $17.5 million favorable impact on sales, with an $12.2 million increase attributable to the 0.1 million Bbl increase in oil production volumes and an $12.0 million increase due to the 0.3 million Bbl increase in NGL production volumes, partially offset by a $6.7 million decrease due to the 3.2 Bcf decrease 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 six months ended June 30, 2013 and 2012:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Six Months Ended June 30, 2013	1,900	1,106	15.5	5,597	$ 105.91	$ 29.83	$ 3.42
Six Months Ended June 30, 2012	1,789	805	18.7	5,717	$ 109.98	$ 39.94	$ 2.09

For the six months ended June 30, 2013 and 2012, we recorded a net gain of $1.2 million and a net gain of $2.3 million, respectively, related to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying condensed statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been $105.73 and $111.24 for the six months ended June 30, 2013 and 2012, respectively, and our average natural gas price would have been $3.52 and $2.09 for the six months ended June 30, 2013 and 2012, respectively.

Costs and Expenses — Six Months Ended June 30, 2013 and 2012

Our expenses for the first six months of 2013 increased, $6.5 million, or 2%, compared to those in the first six months of 2012, for the reasons noted below.

Lease operating cost. These costs increased $5.0 million, or 10%, compared to the level of such expenses in the first six months of 2012. Costs increased due to activities associated with a well control incident in Lake Washington during the first quarter as well as other South Texas cost increases including chemical treating costs, lease operator expenses and surface maintenance costs, partially offset by less workover expense. Our lease operating costs per Boe produced were $9.72 and $8.64 for the six months ended June 30, 2013 and 2012, respectively.

Transportation and gas processing. These costs increased $1.6 million, or 17%, compared to the level of such expenses in the first six months of 2012. The majority of the increase was due to a one-time out of period adjustment made in the first quarter of 2013. Our Transportation and gas processing costs per Boe produced were $1.95 and $1.63 for the six months ended June 30, 2013 and 2012, respectively.

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Depreciation, Depletion and Amortization (“DD&A”). These expenses decreased $3.1 million, or 3% from those in the first six months of 2012. The decrease was due to higher reserve volumes partially offset by a higher depletable base including higher future development costs. Our DD&A rate per Boe of production was $21.36 and $21.45 in the six months ended June 30, 2013 and 2012, respectively.

General and Administrative Expenses, Net. These expenses decreased $0.2 million, or 1%, from the level of such expenses in the first six months of 2012. The decrease was primarily due to a lower corporate benefit accrual and lower deferred compensation, partially offset by higher salaries and burdens and higher temporary labor costs. For the six months ended June 30, 2013 and 2012, our capitalized general and administrative costs totaled $16.0 million and $16.2 million, respectively. Our net general and administrative expenses per Boe produced increased to $4.27 per Boe in the first six months of 2013 from $4.21 per Boe in the first six months of 2012. The supervision fees recorded as a reduction to general and administrative expenses were $6.1 million and $5.8 million for the six months ended June 30, 2013 and 2012, respectively.

Severance and Other Taxes. These expenses decreased $4.9 million, or 19%, from first six months of 2012 levels. Severance and other taxes, as a percentage of oil and gas sales, were approximately 7.1% and 9.4% in the six months ended June 30, 2013 and 2012, respectively. The decrease was primarily driven by a shift in oil production to South Texas, as our Texas oil production carries a lower severance rate then our Louisiana oil production. We also received a refund of approximately $0.8 million related to over payments in prior years.

Interest. Our gross interest cost in the first six months of 2013 was $37.6 million, of which $3.8 million was capitalized. Our gross interest cost in the first six months of 2012 was $30.8 million, of which $4.0 million was capitalized. The increase came from the additional $150.0 million of senior notes due 2022 that were issued in October 2012 along with additional borrowings on our credit facility.

Income Taxes. Our effective income tax rate was 38.4% and 40.0% for the six months ended June 30, 2013 and 2012, respectively. 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.

Liquidity and Capital Resources

Net Cash Provided by Operating Activities. For the first six months of 2013, our net cash provided by operating activities was $149.5 million, representing a 4% decrease compared to $155.7 million generated during the same period of 2012. The decrease was mainly due to changes in working capital.

Working Capital and Debt to Capitalization Ratio. Our working capital decreased from a deficit of $96.9 million at December 31, 2012, to a deficit of $134.4 million at June 30, 2013. Working capital, which is calculated as current assets less current liabilities, can be used to measure both a company's operational efficiency and short-term financial health. The Company uses this measure to track our short-term financial position. Our working capital ratio does not include available liquidity through our credit facility. Our debt to capitalization ratio was 49% and 47% at June 30, 2013 and December 31, 2012, respectively.

Existing Credit Facility. After the regularly scheduled review of our credit facility, the Company's borrowing base and commitment amounts remained unchanged at $450.0 million effective April 26, 2013. The maturity of the credit facility is November 1, 2017.

At June 30, 2013, we had $160.0 million in outstanding borrowings under our credit facility. 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.

2012 Debt Issuance. On October 3, 2012, we issued an additional $150.0 million of 7.875% senior notes due on March 1, 2022. The notes were issued at 105% of par, which equates to a yield to worst of 6.993%. The proceeds from this debt issuance were used to pay down the balance on our credit facility which increased our available liquidity.

Contractual Commitments and Obligations

In May 2013, the Company entered into a new 12.5 year lease agreement for office space in Houston, Texas under the terms of an operating lease, with the lease commencing on or after March 1, 2015, and with minimum contractual obligations of approximately $104 million in the aggregate. We will amortize the total payments required under the lease agreement on a straight-line basis over the term of the lease.

We had no other material changes in our contractual commitments and obligations from December 31, 2012 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, 2012.

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.

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 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, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test").

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.

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 materially 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 June 30, 2013.

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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 pricing expectations;
• 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;
• opportunities to monetize assets;
• 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, 2012. 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.

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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 commodity pricing volatility has continued with unpredictable price swings throughout 2012 and into 2013.

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 Risk – At June 30, 2013, we had natural gas price floors in effect that covered natural gas production of 1,240,000 MMBtu from August 2013 through September 2013, natural gas collars in effect that covered natural gas production of 3,010,000 MMBtu from August 2013 through December 2013 and natural gas participating collars in effect that covered natural gas production of 1,800,000 MMBtu from October 2013 through December 2013. In addition we had had oil participating collars in effect that covered oil production of 201,000 barrels from July 2013 through September 2013.

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.

Concentration of Sales Risk. 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 short-term sales agreements we have in place as well as the size, reputation and nature of their business.

Interest Rate Risk. Our senior notes due in 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 June 30, 2013, we had $160.0 million drawn 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.

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Item 4. Controls and Procedures

Disclosure Controls and Procedures

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

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the first six months of 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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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 2012 Annual Report on Form 10-K.

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

The following table summarizes repurchases of our common stock occurring during the second quarter of 2013:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
04/01/13 – 04/30/13 (1)	409	$ 13.03	—	$—
05/01/13 – 05/31/13 (1)	356	$ 14.08	—	—
06/01/13 – 06/30/13 (1)	1,099	$ 12.62	—	—
Total	1,864	$ 12.99	—	$—

(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 4. Mine Safety Disclosures.

None.

Item 5. Other Information.

On July 30, 2013, the Company's Board of Directors amended and restated the Company's bylaws effective as of adoption on that date, primarily to (i) revise the advance notice provisions for shareholders proposing business or nominating directors; (ii) add procedural and disclosure requirements for shareholders proposing business or nominating directors, calling special meetings or taking action by written consent; and (iii) update and modernize other bylaw provisions, including revisions related to the use of modern electronic communication technologies and changes made for conformance with the current provisions of the Texas Business Organizations Code ("TBOC").

In particular, the changes to the bylaws include:

1. Establishment of new advance notice and related procedural and disclosure requirements, which (i) require advance notice of a shareholder or beneficial owner (a “proposing person”) proposing business or nominating directors in connection with annual or special meetings of shareholders, along with compliance with procedural and informational requirements regarding the proposing person or proposed business, the proposing person's ownership of referenced securities of the Company and related information and (ii) clarify that if the proposing person (or a qualified representative of such proposing person) does not appear at the meeting to present a nomination or proposed business, the nominee or proposal will not be considered.

2. Amendments and clarifications to provisions regarding directors, including those pertaining to filling of vacancies, establishing new notice and written consent procedures for meetings of the board, including revisions to allow for notice of special meetings of the board to be given 24 hours prior to the meeting, and revisions to provisions regarding board committees.

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3. Aligning provisions pertaining to officers more closely to current practice, including adding officers and additional flexibility regarding officer appointments.

4. Updating and modernization of provisions in light of changes made to the Texas Business Organizations Code over recent years, including modifications to provisions on notice, record dates, consents, proxies, voting procedures, conduct of meetings and meeting participation, and changes to accommodate use of modern communication technologies.

5. Addition of a forum selection clause specifying state or federal courts located in the State of Texas as the sole and exclusive forum for proceedings which, among other things, are brought on behalf of the Company, claim breaches of fiduciary duty, arise under the Company's governing documents or the TBOC, or are governed by the internal affairs doctrine.

The foregoing is only a summary of certain changes contained in the Company's amended and restated bylaws. Such summary is qualified in its entirety by reference to the Company's Fourth Amended and Restated Bylaws, a copy of which is filed as Exhibit 3.1 to this Quarterly Report on Form 10-Q, and incorporated herein by reference.

Item 6. Exhibits.

3.1*	Fourth Amended and Restated Bylaws of Swift Energy Company dated July 30, 2013.
10.1	Second Amended and Restated Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May 24, 2013, 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.

*Filed herewith

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SIGNATURES

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

		SWIFT ENERGY COMPANY (Registrant)
Date:	August 1, 2013	By: /s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President and Chief Financial Officer
Date:	August 1, 2013	By: /s/ Barry S. Turcotte Barry S. Turcotte Vice President, Controller and Principal Accounting Officer

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