SWIFT ENERGY CO
Form 10-Q
May 02, 2014

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

FORM 10-Q

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

For the quarterly period ended March 31, 2014
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)	43,807,946 Shares (Outstanding at April 30, 2014)

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SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2014
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Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries (in thousands, except share amounts)

	March 31, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current Assets:		
Cash and cash equivalents	$91	$3,277
Accounts receivable	73,082	70,897
Deferred tax asset	5,572	4,974
Other current assets	10,081	7,600
Total Current Assets	88,826	86,748
Property and Equipment:		
Property and Equipment, including $66,246 and $71,452 of unproved property costs not being amortized, respectively	5,813,305	5,714,099
Less – Accumulated depreciation, depletion, and amortization	(3,236,443)	(3,174,453)
Property and Equipment, Net	2,576,862	2,539,646
Other Long-Term Assets	15,585	17,199
Total Assets	$2,681,273	$2,643,593
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$81,182	$83,361
Accrued capital costs	56,533	61,164
Accrued interest	13,140	21,561
Undistributed oil and gas revenues	13,170	10,990
Total Current Liabilities	164,025	177,076
Long-Term Debt	1,175,036	1,142,368
Deferred Tax Liabilities	224,230	217,384
Asset Retirement Obligation	64,503	63,225
Other Long-Term Liabilities	9,831	10,324
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, 44,234,819 and 43,915,346 shares issued, and 43,804,946 and 43,401,920 shares outstanding, respectively	442	439
Additional paid-in capital	764,058	761,972
Treasury stock held, at cost, 429,873, and 513,426 shares, respectively	(9,645)	(12,575)
Retained earnings	288,793	283,380
Total Stockholders’ Equity	1,043,648	1,033,216
Total Liabilities and Stockholders’ Equity	$2,681,273	$2,643,593

See accompanying Notes to Condensed Consolidated Financial Statements.

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

	Three Months Ended March 31,	
	2014	2013
Revenues:		
Oil and gas sales	$148,558	$146,477
Price-risk management and other, net	(4,877)	(240)
Total Revenues	143,681	146,237
Costs and Expenses:		
General and administrative, net	10,739	12,725
Depreciation, depletion, and amortization	61,685	60,120
Accretion of asset retirement obligation	1,386	1,775
Lease operating cost	25,267	27,424
Transportation and gas processing	5,292	6,030
Severance and other taxes	9,202	9,775
Interest expense, net	18,449	16,802
Total Costs and Expenses	132,020	134,651
Income Before Income Taxes	11,661	11,586
Provision for Income Taxes	6,248	4,377
Net Income	$5,413	$7,209
Per Share Amounts-		
Basic: Net Income	$0.12	$0.17
Diluted: Net Income	$0.12	$0.17
Weighted Average Shares Outstanding - Basic	43,628	43,167
Weighted Average Shares Outstanding - Diluted	44,118	43,603

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, 2012	$435	$747,868	$(13,855)	$302,412	$1,036,860
Stock issued for benefit plans (104,890 shares)	—	(1,171)	2,793	—	1,622
Shares issued from option exercises (1,125 shares)	—	4	—	—	4
Purchase of treasury shares (98,020 shares)	—	—	(1,513)	—	(1,513)
Tax shortfall from share-based compensation	—	(1,607)	—	—	(1,607)
Employee stock purchase plan (72,273 shares)	1	945	—	—	946
Issuance of restricted stock (391,581 shares)	3	(3)	—	—	—
Amortization of share-based compensation	—	15,936	—	—	15,936
Net Loss	—	—	—	(19,032)	(19,032)
Balance, December 31, 2013	$439	$761,972	$(12,575)	$283,380	$1,033,216
Stock issued for benefit plans (154,665 shares) (1)	—	(1,876)	3,785	—	1,909
Purchase of treasury shares (71,112 shares) (1)	—	—	(855)	—	(855)
Employee stock purchase plan (71,825 shares) (1)	1	823	—	—	824
Issuance of restricted stock (247,648 shares) (1)	2	(2)	—	—	—
Amortization of share-based compensation (1)	—	3,141	—	—	3,141
Net Income (1)	—	—	—	5,413	5,413
Balance, March 31, 2014	$442	$764,058	$(9,645)	$288,793	$1,043,648

(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)

	Three Months Ended March 31, 2014	2013
Cash Flows from Operating Activities:		
Net income	$5,413	$7,209
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion, and amortization	61,685	60,120
Accretion of asset retirement obligation	1,386	1,775
Deferred income taxes	6,248	4,377
Share-based compensation expense	2,054	3,015
Other	(3,216)	(3,864)
Change in assets and liabilities-		
(Increase) decrease in accounts receivable	(2,335)	(5,191)
Increase (decrease) in accounts payable and accrued liabilities	6,885	3,085
Increase (decrease) in accrued interest	(8,421)	(8,303)
Net Cash Provided by Operating Activities	69,699	62,223
Cash Flows from Investing Activities:		
Additions to property and equipment	(105,589)	(132,981)
Proceeds from the sale of property and equipment	35	999
Net Cash Used in Investing Activities	(105,554)	(131,982)
Cash Flows from Financing Activities:		
Proceeds from bank borrowings	115,300	265,600
Payments of bank borrowings	(82,600)	(195,300)
Net proceeds from issuances of common stock	824	946
Purchase of treasury shares	(855)	(1,409)
Net Cash Provided by Financing Activities	32,669	69,837
Net increase (decrease) in Cash and Cash Equivalents	(3,186)	78
Cash and Cash Equivalents at Beginning of Period	3,277	170
Cash and Cash Equivalents at End of Period	$91	$248
Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	$26,310	$24,626

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 note 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, 2013 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 liabilities, 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 adjustments occur.

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 March 31, 2014 and 2013, such internal costs capitalized totaled $7.1 million and $9.1 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the three months ended March 31, 2014 and 2013, capitalized interest on unproved properties totaled $1.3 million and $1.9 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

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

(in thousands)	March 31, 2014	December 31, 2013
Property and Equipment		
Proved oil and gas properties	$5,704,702	$5,600,279
Unproved oil and gas properties	66,246	71,452
Furniture, fixtures, and other equipment	42,357	42,368
Less – Accumulated depreciation, depletion, and amortization	(3,236,443)	(3,174,453)
Property and Equipment, Net	$2,576,862	$2,539,646

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.

It is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the near term and that non-cash write-downs of oil and natural gas properties would occur in the future. If future capital expenditures out pace future discounted net cash flows in our reserve calculations, 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) or if oil or natural gas prices decline, non-cash write-downs of our oil and natural gas properties could occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties due to decreases in oil or natural gas prices.

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Swift Energy uses the entitlement method of accounting in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying condensed consolidated balance sheets. Natural gas balancing receivables are reported in "Other current assets" on the accompanying condensed consolidated balance sheets when our ownership share of production exceeds sales. As of March 31, 2014 and December 31, 2013, we did not have any material natural gas imbalances.

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

Accounts Receivable. We assess the collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At March 31, 2014 and December 31, 2013, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balance on the accompanying condensed consolidated balance sheets.

At March 31, 2014, our "Accounts receivable" balance included $59.5 million for oil and gas sales, $1.2 million for joint interest owners, $12.1 million for severance tax credit receivables and $0.3 million for other receivables. At December 31, 2013, our "Accounts receivable" balance included $56.9 million for oil and gas sales, $1.6 million for joint interest owners, $11.6 million for severance tax credit receivables and $0.8 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 senior 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 March 31, 2014, was $1.7 million. The 8.875% senior notes due in 2020 mature on January 15, 2020, and the balance of their issuance costs at March 31, 2014, was $3.4 million. The 7.875% senior notes due in 2022 mature on March 1, 2022, and the balance of their issuance costs at March 31, 2014, was $6.4 million. The balance of revolving credit facility issuance costs at March 31, 2014, was $3.1 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 in earnings unless specific hedge accounting criteria are met. We have not elected special hedge accounting treatment for our hedges therefore the changes in the fair value of our derivatives 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 swaps, floors, calls, collars and participating collars.

During the three months ended March 31, 2014 and 2013, we recorded net losses of $5.1 million and $0.3 million, respectively, relating to our derivative activities. These amounts include a revenue reduction of $3.4 million during the first quarter of 2014 for the non-cash fair value adjustments on commodity derivatives. 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 commonly accepted industry-standard models and are periodically verified against quotes from brokers. The fair value of our unsettled derivative assets at March 31, 2014 was $0.3 million which was recognized on the accompanying condensed consolidated balance sheet in "Other current assets." The fair value of our unsettled derivative liabilities at March 31, 2014 was $3.8 million which was recognized on the accompanying condensed consolidated balance sheet in "Accounts payable and accrued liabilities."

At March 31, 2014, we had less than $0.1 million in receivables for settled derivatives which were recognized on the accompanying condensed consolidated balance sheet in "Accounts receivable" and were subsequently collected in April 2014. At March 31, 2014, we also had $0.7 million in payables for settled derivatives which were recognized on the accompanying condensed consolidated balance sheet in "Accounts payable and accrued liabilities" and were subsequently paid in April 2014.

The Company uses an International Swap and Derivatives Association "ISDA" master agreement for all derivative contracts. This is an industry standardized contract containing the general conditions of our derivative transactions including provisions relating to netting derivative settlement payments under certain circumstances (such as default). For reporting purposes, the Company has elected to not offset the asset and liability fair value amounts of its derivatives on the accompanying balance sheets. If all counterparties were in a default situation, the Company, under the right of set-off, would show a net derivative fair value liability of $3.5 million at March 31, 2014. For further discussion related to the fair value of the Company's derivatives, refer to Note 7 of these condensed consolidated financial statements.

The following tables summarize the weighted average prices and future production volumes for our unsettled derivative contracts in place as of March 31, 2014.

Oil Derivatives (NYMEX WTI Settlements)	Total Volumes (Bbls)	Swap Fixed Price
2014 Contracts		
Swaps	297,500	$98.15

Natural Gas Derivatives (NYMEX Henry Hub Settlements)	Total Volumes (MMBtu)	Swap Fixed Price	Collars Floor Price	Ceiling Price
2014 Contracts				
Swaps	8,880,000	$4.26		
Collars	3,340,000		$4.12	$4.43

2015 Contracts		
Swaps	900,000	$4.42

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Natural Gas Basis Derivatives (East Texas Houston Ship Channel Settlements)	Total Volumes (MMBtu)	Swap Fixed Price
2014 Contracts		
Swaps	9,600,000	$ 0.09

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 months ended March 31, 2014 and 2013 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated were $2.8 million in the three months ended March 31, 2014 and 2013, respectively.

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 $3.3 million and $3.5 million at March 31, 2014 and December 31, 2013, 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 March 31, 2014, we did not have any accrued liability for uncertain tax positions and do not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months.

Our U.S. Federal income tax returns for 2007 forward, our Louisiana income tax returns from 1999 forward and our Texas franchise tax returns after 2008 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 jurisdiction returns are significant to our financial position.

For the three months ended March 31, 2014, we recognized an income tax expense increase of $1.7 million related to a shortfall between the tax deduction received with respect to prior restricted stock grants that vested in the quarter versus the actual book expense recorded over the life of those grants.

Accounts Payable and Accrued Liabilities. The "Accounts payable and accrued liabilities" balances on the accompanying condensed consolidated balance sheets are summarized below (in thousands):

	March 31, 2014	December 31, 2013
Trade accounts payable (1)	$ 24,760	$ 30,769
Accrued operating expenses	18,126	17,059
Accrued payroll costs	10,550	10,938
Asset retirement obligation – current portion	14,586	15,859
Accrued taxes	6,874	5,845
Other payables	6,286	2,891
Total accounts payable and accrued liabilities	$ 81,182	$ 83,361

(1) Included in “trade accounts payable” are liabilities of approximately $10.9 million and $26.1 million at March 31, 2014 and December 31, 2013, 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.

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Restricted Cash. These balances primarily include amounts held in escrow accounts to satisfy plugging and abandonment obligations. As of March 31, 2014 and December 31, 2013, 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.

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

	2014
Asset Retirement Obligation recorded as of January 1	$ 79,084
Accretion expense	1,386
Liabilities incurred for new wells and facilities construction	40
Reductions due to sold and abandoned wells and facilities	(1,685)
Revisions in estimates	264
Asset Retirement Obligation as of March 31	$ 79,089

At March 31, 2014 and December 31, 2013, approximately $14.6 million and $15.9 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 March 31, 2014.

(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 2, 2014, 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, 2013, 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 months ended March 31, 2014, we recognized an income tax shortfall in earnings of $1.7 million related to restricted stock awards that vested at a price lower than the grant date fair value. For the three months ended March 31, 2013, we did not recognize any excess tax benefit or shortfall in earnings. There were no stock option exercises for the three months ended March 31, 2014 and 2013.

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 $1.9 million and $2.8 million for the three months ended March 31, 2014 and 2013, respectively. Share-based compensation recorded in lease operating cost was less than $0.1 million for the three months ended March 31, 2014 and 2013. We also capitalized $1.1 million and $1.6 million of share-based compensation for the three months ended March 31, 2014 and 2013, 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.

Stock Option Awards

We use the Black-Scholes-Merton option pricing model to estimate the fair value of stock option awards. During the three months ended March 31, 2014 and 2013 we did not grant any stock option awards.

At March 31, 2014, we had $0.4 million of unrecognized compensation cost related to stock option awards, which is expected to be recognized over a weighted-average period of 0.9 years. The following table represents stock option award activity for the three months ended March 31, 2014:

	Shares	Wtd. Avg. Exercise Price
Options outstanding, beginning of period	1,488,314	$ 33.38
Options granted	—	$ —
Options canceled	(14,264)	$ 22.32
Options exercised	—	$ —
Options outstanding, end of period	1,474,050	$ 33.46
Options exercisable, end of period	1,368,912	$ 33.52

Our stock option awards outstanding and exercisable at March 31, 2014 were out of the money and therefore had no aggregate intrinsic value. At March 31, 2014, the weighted average contract life of stock option awards outstanding was 5.1 years and the weighted average contract life of stock option awards exercisable was 4.9 years. There were no stock option exercises for the three months ended March 31, 2014 and 2013.

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, 2013, allow for the issuance of restricted stock awards that generally may not be sold or otherwise transferred until certain restrictions have lapsed. The unrecognized compensation cost related to these awards is expected to be expensed over the period the restrictions lapse (generally one to three years).

The compensation expense for these awards was determined based on the closing market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of March 31, 2014, we had unrecognized compensation expense of $14.5 million related to restricted stock awards which is expected to be recognized over a weighted-average period of 1.9 years. The grant date fair value of shares vested during the three months ended March 31, 2014 was $9.2 million.

The following table represents restricted stock award activity for the three months ended March 31, 2014:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	1,267,110	$ 21.54
Restricted shares granted	325,550	$ 12.32
Restricted shares canceled	(5,676)	$ 16.50
Restricted shares vested	(247,648)	$ 37.10
Restricted shares outstanding, end of period	1,339,336	$ 16.44

Performance-Based Restricted Stock Units

For the three months ended March 31, 2014 and 2013, the Company granted 185,250 and 189,700 units, respectively, of performance-based restricted stock units containing predetermined market and performance conditions with a cliff vesting period of 3.1 years. These units were granted at 100% of target payout while the conditions of the grants allow for a payout ranging between no payout and 200% of target.

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The compensation expense for the market condition is based on the per unit grant date valuation using a Monte-Carlo simulation. The performance condition is remeasured quarterly and compensation expense is recorded based on the closing market price of our stock per unit on the grant date 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.

As of March 31, 2014, we had unrecognized compensation expense of $3.6 million related to our restricted stock units which is expected to be recognized over a weighted-average period of 2.5 years. No shares vested during the three months ended March 31, 2014 and 2013. The weighted average grant date fair value for the restricted stock units granted during the three months ended March 31, 2014 and 2013 was $11.68 and $15.01 per unit, respectively.

The following table represents restricted stock unit activity for the three months ended March 31, 2014.

	Shares	Wtd. Avg. Grant Price
Restricted stock units outstanding, beginning of period	189,700	$ 15.01
Restricted stock units granted	185,250	$ 11.68
Restricted stock units canceled	—	$ —
Restricted stock units vested	—	$ —
Restricted stock units outstanding, end of period	374,950	$ 13.36

(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 earnings per share ("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 months ended March 31, 2014 and 2013, and are discussed below.

Due to amendments to our stock plan agreement made in May 2013, 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 months ended March 31, 2014 and 2013 (in thousands, except per share amounts):

	Three Months Ended March 31, 2014			Three Months Ended March 31, 2013		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$ 5,413	43,628	$ 0.12	$ 7,209	43,167	$ 0.17
Dilutive Securities:						
Stock Options		—			34	
Restricted Stock Awards		420			280	
Restricted Stock Units		70			122	

Diluted EPS:						
Net Income and Assumed Share Conversions	$5,413	44,118	$0.12	$7,209	43,603	$0.17

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Approximately 1.5 million and 1.4 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months ended March 31, 2014 and 2013, respectively, because these stock options were antidilutive. Approximately 0.4 million and 0.3 million restricted stock awards were not included in the computation of Diluted EPS for the three months ended March 31, 2014 and 2013, respectively, because they were antidilutive. Approximately 0.7 million and 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 months ended March 31, 2014 and 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 March 31, 2014 and December 31, 2013, was as follows (in thousands):

	March 31, 2014	December 31, 2013
7.125% senior notes due in 2017	$ 250,000	$ 250,000
8.875% senior notes due in 2020 (1)	222,526	222,446
7.875% senior notes due in 2022 (1)	404,810	404,922
Bank Borrowings due in 2017	297,700	265,000
Long-Term Debt (1)	$ 1,175,036	$ 1,142,368

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

As of March 31, 2014, we had $297.7 million of outstanding bank borrowings on our credit facility which has a maturity date of November 1, 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 $1.3 million and $1.9 million for the three months ended March 31, 2014 and 2013, respectively.

Bank Borrowings. Effective April 30, 2014, our syndicate of 11 banks reaffirmed the borrowing base of $450.0 million on our $500.0 million credit facility. The commitment amount of $450.0 million and maturity date of November 1, 2017 remained unchanged.

We had $297.7 million and $265.0 million in outstanding borrowings under our credit facility at March 31, 2014 and December 31, 2013, 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 March 31, 2014, the lead bank's prime rate was 3.25% and the commitment fee associated with the credit facility was 0.5%.

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 March 31, 2014, we were in compliance with the provisions of this agreement. The credit facility is secured by our 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 $2.1 million and $1.2 million for the three months ended March 31, 2014 and 2013, respectively. The amount of commitment fees included in interest expense, net was $0.2 million and $0.3 million for the three months ended March 31, 2014 and 2013, respectively.

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 condensed 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 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. 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 and 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 March 31, 2014.

Interest expense on the senior notes due in 2022, including amortization of debt issuance costs and debt premium, totaled $7.9 million for the three months ended March 31, 2014 and 2013.

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. Interest on these notes is payable semi-annually on January 15 and July 15 and commenced on January 15, 2010. 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 and 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 March 31, 2014.

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 March 31, 2014 and 2013.

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. 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

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investments, transfer or sell assets, enter into transactions with affiliates and 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 March 31, 2014.

Interest expense on the senior notes due in 2017, including amortization of debt issuance costs, totaled $4.6 million for the three months ended March 31, 2014 and 2013.

(6) Acquisitions and Dispositions

There were no material acquisitions or dispositions in the three months ended March 31, 2014 and 2013, respectively.

(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 March 31, 2014 and December 31, 2013, the fair value and carrying value of our senior notes was as follows (in millions):

	March 31, 2014		December 31, 2013	
	Fair Value	Carrying Value	Fair Value	Carrying Value
7.125% senior notes due in 2017	$253.4	$250.0	$256.7	$250.0
8.875% senior notes due in 2020	$236.3	$222.5	$239.1	$222.4
7.875% senior notes due in 2022	$408.2	$404.8	$409.0	$404.9

Our senior notes due in 2017, 2020 and 2022 are stated as liabilities at carrying value on our accompanying condensed consolidated balance sheets, 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 and liabilities that are measured at fair value as of March 31, 2014 and December 31, 2013, and are categorized using the fair value hierarchy. For additional discussion related to the fair value of the Company's derivatives, refer to Note 2 of these condensed consolidated financial statements. 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)
March 31, 2014				
Assets:				
Natural Gas Derivatives	$0.3	$—	$0.3	$—
Liabilities:				
Natural Gas Derivatives	2.7	—	2.7	—
Gas Basis Derivatives	0.3	—	0.3	—
Oil Derivatives	0.8	—	0.8	—
December 31, 2013				
Assets:				
Natural Gas Derivatives	$0.5	$—	$0.5	$—
Oil Derivatives	0.3	—	0.3	—
Liabilities:				
Natural Gas Derivatives	0.7	—	0.7	—
Oil Derivatives	0.2	—	0.2	—

Our unsettled derivative assets and liabilities in the table above are measured at gross fair value and are shown on the accompanying condensed consolidated balance sheets in “Other current assets” and "Accounts payable and accrued liabilities", respectively.

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.

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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, 2013 and 2012. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 25 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 hold a large acreage position in Texas prospective for Eagle Ford shale and Olmos tight sands development and are one of the largest producers of crude oil in the state of Louisiana. Oil production accounted for 32% of our first quarter 2014 production and 62% of our oil and gas sales, and combined production of both oil and natural gas liquids ("NGLs") constituted 48% of our first quarter 2014 production and 74% 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.

First Quarter 2014 Activities

- Production: Our production volumes increased by 4% in the first quarter of 2014 when compared to volumes in the same period in 2013 as oil volumes decreased by 6%, NGL volumes decreased by 14% and natural gas production volumes increased by 21%. The change in oil production volumes resulted from our Southeast Louisiana operations while the change in NGL and natural gas volumes primarily came from our South Texas operations. Sequentially, production volumes decreased by 5% in the first quarter of 2014 compared to fourth quarter of 2013 levels as oil volumes decreased by 9%, NGL volumes decreased by 22% and natural gas production volumes increased by 6%. The change in oil production volumes are attributable to operations in our South Texas and Southeast Louisiana areas while the change in NGL and natural gas volumes was primarily from our South Texas area.

- Pricing: Our weighted average sales price in the first quarter of 2014 decreased by 3% when compared to average price levels in the first quarter of 2013. When compared to pricing in the first quarter of 2013, oil prices in the first quarter of 2014 decreased 8%, NGL prices increased 21% and natural gas prices increased 42%. Sequentially, when comparing first quarter of 2014 pricing to pricing in the fourth quarter of 2013, oil prices increased 6%, NGL prices increased 7% and natural gas prices increased 26%.

- Cash provided by operating activities: For the first three months of 2014, our cash provided by operating activities increased by $7.5 million or 12%, when compared to levels in the first three months of 2013, due primarily to working capital changes.

- Available liquidity: At March 31, 2014, we had $297.7 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 $152 million of liquidity. We plan to utilize amounts received from any asset sales and joint ventures entered into during 2014 to strengthen our balance sheet and fund a portion of our 2014 capital expenditures. The completion of either of these transactions will affect our 2014 capital expenditures as we align our capital expenditures with our expected cash flows.

- 2014 capital expenditures: Our capital expenditures on a cash flow basis were $105.6 million in the first three months of 2014, compared to $133.0 million in the first three months of 2013. The expenditures were mainly due to drilling and completion activity in our South Texas core region as we drilled six wells in our AWP Eagle Ford field and five wells in our Fasken field. These expenditures were funded by $69.7 million of cash provided by operating activities and the remainder through borrowings under our credit facility.

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Strategy and Outlook

- Full Year 2014 Planned Capital Expenditures: Our 2014 planned capital expenditures are $300 to $350 million. We currently plan to fund our 2014 capital expenditures with our operating cash flow. We expect that a portion of any proceeds from joint ventures we enter involving our properties in the Fasken Eagle Ford area (see below) and/or proceeds from the disposition of all or a portion of our Central Louisiana assets (see below) will allow us to increase our level of capital expenditures while still allowing us to reduce our debt. If we do not receive such joint venture or disposition proceeds, we will align our capital spending with our expected cash flows. These amounts are flexible and will be adjusted based on the timing of any joint venture or disposition transactions and market fundamentals. For 2014, the Company continues to target annual production levels of 11.3 to 11.8 MMBoe based on the above spending levels.

- Pursuit of Eagle Ford Joint Venture: We are currently engaged in negotiations regarding a joint venture arrangement for a portion of our natural gas properties in the Eagle Ford area, principally our natural gas properties in the Fasken area. Entering into a joint venture agreement could accelerate drilling and development, monetize a portion of those asset values and further diversify our risk profile. We are targeting completion of this initiative by mid-year 2014.

- Central Louisiana Property Disposition: We are currently negotiating with prospective buyers to sell some or all of our Austin Chalk and Wilcox assets in Central Louisiana in order to focus our spending on our South Texas properties. We will continue these negotiations and expect to either complete a sale of some or all of these properties or pursue an ongoing development plan of our own. These Central Louisiana assets include approximately 86,000 mineral acres and three producing oil and natural gas fields: Burr Ferry, Masters Creek, and South Bearhead Creek.

- Reduced Spending for 2014: We are planning a reduced level of capital spending for 2014 to levels more in line with our internally generated cash flow and some portion of any joint venture and/or disposition. Our priorities are financial discipline first and growth second. We expect to continue focusing on South Texas production and reserves, while maintaining a stronger balance sheet. Either or both transactions discussed above would initially reduce the borrowing base on our line of credit, but would also lower our leverage and enhance our liquidity, given that the expected proceeds would exceed any associated borrowing base reduction. We have been and will continue taking steps to reduce our future operating and overhead costs through a number of initiatives, including reducing personnel in conjunction with any asset dispositions and alignment of our other expenses, including the cancellation of a new lease for future corporate office space, which will allow us to seek out more efficient and cost effective space.

- Operating improvements through new Eagle Ford drilling and completion technology: Our South Texas drilling activities continue to benefit from optimized well design as we are drilling longer laterals in our horizontal wells and performing more frac stages per well. When we began drilling in the Eagle Ford, our average lateral length was approximately 3,000 feet, and we performed up to nine frac stages per well. Our current process allows us to drill laterals of over 6,000 feet and complete 20 or more frac stages per well. We have observed a high correlation between the lateral length and number of frac stages in horizontal Eagle Ford wells, along with improved initial performance and long-term cumulative production. Additionally, as several of our peers have also announced, we are now increasing the number of frac stages per 1,000 feet of lateral length and using greater amounts of proppant with each frac as we believe these changes could bring further improvement in our results.

- Improved performance of Eagle Ford shale assets through reduction in per well costs: We have seen improved performance this year in our initial production (IP) rates for Eagle Ford wells and have also seen our per well drilling and completion costs come down from those experienced in the prior year. With faster drilling times, we are currently able to drill more wells per rig than previously expected. We have also experienced efficiency gains in our hydraulic fracturing activities (fracs), which enable us to perform more frac stages per month, lower the overall frac cost per stage and achieve better overall results. We believe that progression along this technology learning curve is important to improving performance and reducing costs. As an example, we continued to see excellent production results from our recently completed wells in our Fasken area during the first quarter of 2014, which have been our most prolific wells in that area.

- Advances in 3D Geoscience technologies allow more targeted drilling: We are utilizing state of the art geoscience technologies to improve our lateral placements and completion design in the Eagle Ford and to better define our undeveloped resource potential in Lake Washington. In the Eagle Ford, GEOFRAC logging of the horizontal well bore has led to more effective placement of frac stages and also assisted in identifying sections of rock that are not ideal for stimulation, affording opportunities to eliminate potentially non-productive frac stages. We have been able to utilize our 3D seismic data in this area, along with the analysis of cores and well logs, to identify a narrow high quality interval of

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the lower Eagle Ford within which to steer our laterals, resulting in marked improvement in our well results. We recently acquired 3D seismic data over our Fasken area, which we believe will allow us additional improvement in drilling results in this area. In our Lake Washington area, we have applied new state of the art tools to better define the undeveloped resources in the field. We recently obtained some additional 3D seismic data over the southern area at Lake Washington and will be merging and reprocessing it with our proprietary 3D seismic data. With the help of this new data along with these new tools, we expect to identify additional unevaluated development potential in this field.

- Ability to capitalize on increased natural gas prices in the future: Although current natural gas prices are lower than historical highs, prices have improved significantly from the lows seen in the last several years. With increasing demand, including the volume of LNG available for export increasing over the next several years, we believe natural gas prices will increase from current levels and that selected natural gas properties can be economically developed in today’s market, although much of the potential for natural gas development will require higher prices. Our Fasken properties in Webb County, which include some of the best Eagle Ford rock in South Texas as defined by porosity, total organic content and other geologic and petrophysical qualities, can be economically developed today. Some areas such as potential natural gas resources in our South AWP area in McMullen County may require a higher price environment to provide adequate economic returns, but we believe there are other potential areas in South Texas that can be developed economically in the current environment. Our strategy includes a balanced approach to oil and natural gas, and as such, we plan to continue some development on our prolific natural gas properties, such as Fasken.

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Results of Operations

Revenues — Three Months Ended March 31, 2014 and 2013

Our oil and gas sales in the first quarter of 2014 increased by 1% compared to oil and gas sales in the first quarter of 2013, due to higher natural gas pricing and production, partially offset by lower oil pricing and production. Average oil prices we received were 8% lower than those received during the first quarter of 2013, while natural gas prices were 42% higher, and NGL prices were 21% higher.

Crude oil production was 32% and 35% of our production volumes in the three months ended March 31, 2014 and 2013, respectively. Crude oil sales were 62% and 73% of oil and gas sales in the three months ended March 31, 2014 and 2013, respectively. Natural gas production was 52% and 45% of our production volumes in the three months ended March 31, 2014 and 2013, respectively. Natural gas sales were 26% and 15% of oil and gas sales in the three months ended March 31, 2014 and 2013, respectively. The remaining production and sales 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 March 31, 2014 and 2013:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2014	2013	2014	2013
Southeast Louisiana	$ 37.2	$ 44.1	400	446
South Texas	99.4	86.7	2,350	2,105
Central Louisiana	11.6	15.2	186	249
Other	0.4	0.5	8	19
Total	$ 148.6	$ 146.5	2,944	2,819

In the first quarter of 2014, our $2.1 million, or 1% increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $6.0 million favorable impact on sales, with an increase of $11.4 million attributable to the 42% increase in natural gas prices, a decrease of $8.4 million due to the 8% decrease in average oil prices received and an increase of $3.0 million due to the 21% increase in NGL prices.
- Volume variances that had a $3.9 million unfavorable impact on sales, with a $6.2 million decrease due to a 0.1 million Bbl decrease in oil production volumes and a $2.3 million decrease attributable to the 0.1 million Bbl decrease in NGL production volumes, partially offset by a $4.6 million increase due to the 1.6 Bcf increase in natural gas production volumes.

The following table provides additional information regarding our quarterly oil and gas sales, excluding any effects of our hedging activities, for the three months ended March 31, 2014 and 2013:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Three Months Ended March 31, 2014	931	478	9.2	2,944	$ 99.38	$ 36.27	$ 4.20
Three Months Ended March 31, 2013	988	557	7.6	2,819	$ 108.45	$ 29.90	$ 2.96

For the three months ended March 31, 2014 and 2013, we recorded net losses of $5.1 million and $0.3 million, respectively, related to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying condensed consolidated statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been $98.42 and $108.40 for the three months ended March 31, 2014 and 2013, respectively, and our average natural gas price would have been $3.75 and $2.93 for the three months ended March 31, 2014 and 2013, respectively.

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Costs and Expenses — Three Months Ended March 31, 2014 and 2013

Our expenses in the first quarter of 2014 decreased $2.6 million, or 2%, compared to those in the first quarter of 2013, for the reasons noted below.

Lease operating cost. These expenses decreased $2.2 million, or 8%, compared to the level of such expenses in the first quarter of 2013. The decrease was due to costs associated with a well control incident in Lake Washington during the first quarter of 2013 as well as cost decreases in South Texas for lower salt water disposal costs. Our lease operating costs per Boe produced were $8.58 and $9.73 for the three months ended March 31, 2014 and 2013, respectively.

Transportation and gas processing. These expenses decreased $0.7 million, or 12%, compared to the level of such expenses in the first quarter of 2013 as our NGL production volumes decreased 14%. Our transportation and gas processing costs per Boe produced were $1.80 and $2.14 for the three months ended March 31, 2014 and 2013, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses increased $1.6 million, or 3% from those in the first quarter of 2013. The increase was due to higher production and a higher depletable base including higher future development costs, partially offset by higher reserve volumes. Our DD&A rate per Boe of production improved to $20.95 for the three months ended March 31, 2014, as compared to $21.33 for the three months ended March 31, 2013.

General and Administrative Expenses, Net. These expenses decreased $2.0 million, or 16%, from the level of such expenses in the first quarter of 2013. The decrease was primarily due to lower deferred compensation and a lower benefit accrual partially offset by lower capitalized amounts. For the first quarter of 2014, our capitalized general and administrative costs totaled $7.1 million and $9.1 million, respectively. Our net general and administrative expenses per Boe produced decreased to $3.65 per Boe in the first quarter of 2014 from $4.51 per Boe in the first quarter of 2013. The supervision fees recorded as a reduction to general and administrative expenses were $2.8 million for the three months ended March 31, 2014 and 2013.

Severance and Other Taxes. These expenses decreased $0.6 million, or 6%, from first quarter 2013 levels. Severance and other taxes, as a percentage of oil and gas sales, were approximately 6.2% and 6.7% in the three months ended March 31, 2014 and 2013, respectively. The decrease in the rate was primarily driven by credits from reduced tax rates of gas production related to South Texas completions in prior period wells.

Interest. Our gross interest cost in the first quarter of 2014 was $19.7 million, of which $1.3 million was capitalized. Our gross interest cost in the first quarter of 2013 was $18.7 million, of which $1.9 million was capitalized. The increase came primarily from additional borrowings on our credit facility.

Income Taxes. Our effective income tax rate was 53.6% and 37.8% for the three months ended March 31, 2014 and 2013, respectively. This increase in rate related to a shortfall between the tax deduction received with respect to prior restricted stock grants that vested in the quarter versus the actual book expense recorded over the life of those grants.

Liquidity and Capital Resources

Net Cash Provided by Operating Activities. For the first three months of 2014, our net cash provided by operating activities was $69.7 million, representing a 12% increase compared to $62.2 million generated during the same period of 2013. The increase was mainly due to changes in working capital.

Working Capital and Debt to Capitalization Ratio. Our working capital increased from a deficit of $90.3 million at December 31, 2013, to a deficit of $75.2 million at March 31, 2014. 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 53% at March 31, 2014 and December 31, 2013.

Existing Credit Facility. Our borrowing base was reaffirmed at $450.0 million as of April 30, 2014. The next scheduled borrowing base redetermination occurs in November 2014. At March 31, 2014, we had $297.7 million in outstanding borrowings under our credit facility. Our available borrowings under our credit facility provide us liquidity along with any proceeds received from asset sales. 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.

Asset Dispositions and Joint Ventures. We plan to utilize amounts received from any joint ventures and/or asset sales entered into during 2014 to strengthen our balance sheet, and potentially fund a portion of our 2014 capital expenditures. As

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previously noted; we are currently engaged in negotiations regarding a joint venture arrangement related to our Fasken Eagle Ford acreage and the potential sale of some or all of our Central Louisiana assets with prospective buyers. The completion of one or both of these transactions will affect the level of our 2014 capital expenditures as we better align our capital expenditures with our expected cash flows. Either or both transactions discussed above would initially reduce the borrowing base on our line of credit, but would also lower our leverage and enhance our liquidity, given that the expected proceeds would exceed any associated borrowing base reduction.

Contractual Commitments and Obligations

We had no other material changes in our contractual commitments and obligations from amounts referenced under "Contractual Commitments and Obligations" in Management's Discussion and Analysis in our Annual Report on Form 10-K for the year ending December 31, 2013.

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 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 future capital expenditures out pace future discounted net cash flows in our reserve calculations or 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.

New Accounting Pronouncements. There are no material new accounting pronouncements that have been issued but not yet adopted as of March 31, 2014.

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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;
- estimated oil and natural gas reserves or the present value thereof;
- technology;
- our borrowing capacity, cash flows and liquidity;
- financial strategy, budget, projections and operating results;
- asset disposition efforts or the timing or outcome thereof;
- prospective joint ventures, their structure and substance, and the likelihood of their finalization or the timing thereof;
- oil and natural gas pricing expectations;
- the amount, nature and timing of capital expenditures, including future development costs;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment or availability of oil field labor;
- availability and terms of capital;
- drilling of wells;
- marketing and transportation of oil and natural gas;
- costs of exploiting and developing our properties and conducting other operations;
- competition in the oil and natural gas industry;
- general economic conditions;
- opportunities to monetize assets;
- 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;
- 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, 2013. 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 2013 and into 2014.

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. For additional discussion related to our price-risk management policy, refer to Note 2 of these condensed consolidated financial statements.

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 March 31, 2014, we had $297.7 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 three months of 2014 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 2013 Annual Report on Form 10-K.

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

The following table summarizes repurchases of our common stock occurring during the first quarter of 2014:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
01/01/14 – 01/31/14 (1)	874	$ 13.08	—	$—
02/01/14 – 02/28/14 (1)	69,706	$ 12.02	—	—
03/01/14 – 03/31/14 (1)	532	$ 9.73	—	—
Total	71,112	$ 12.02	—	$—

(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 April 30, 2014, Swift Energy Company and its wholly-owned subsidiary, Swift Energy Operating, LLC, entered into the Fourth Amendment to the Second Amended and Restated Credit Agreement dated as of September 21, 2010, as amended by the First Amendment and Consent dated as of May 12, 2011, and the Second Amendment dated as of October 2, 2012, with JPMorgan Chase Bank, N.A., as Administrative Agent, and institutions named therein as lenders (the "Amendment"). The Amendment re-affirms the Company's borrowing base at $450 million, and Swift Energy elected to retain its commitment amount at $450 million. The Amendment also modifies an existing negative covenant to allow the Company to enter hedging agreements with approved counterparties, as defined in the Amendment.

Item 6. Exhibits.

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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.
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101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

*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:	May 1, 2014	By: /s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President Chief Financial Officer and Principal Accounting Officer

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Exhibit Index

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