SWIFT ENERGY CO
Form 10-Q
August 01, 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 June 30, 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)	43,846,281 Shares (Outstanding at July 31, 2014)

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SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2014
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Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries (in thousands, except share amounts)

	June 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current Assets:		
Cash and cash equivalents	$564	$3,277
Accounts receivable	68,615	70,897
Deferred tax asset	4,829	4,974
Other current assets	21,033	7,600
Total Current Assets	95,041	86,748
Property and Equipment:		
Property and Equipment, including $63,662 and $71,452 of unproved property costs not being amortized, respectively	5,923,457	5,714,099
Less – Accumulated depreciation, depletion, and amortization	(3,308,992)	(3,174,453)
Property and Equipment, Net	2,614,465	2,539,646
Other Long-Term Assets	15,030	17,199
Total Assets	$2,724,536	$2,643,593
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$104,523	$83,361
Accrued capital costs	49,870	61,164
Accrued interest	21,505	21,561
Undistributed oil and gas revenues	11,109	10,990
Total Current Liabilities	187,007	177,076
Long-Term Debt	1,178,301	1,142,368
Deferred Tax Liabilities	229,107	217,384
Asset Retirement Obligation	65,963	63,225
Other Long-Term Liabilities	9,695	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, 44,278,732 and 43,915,346 shares issued, and 43,845,333 and 43,401,920 shares outstanding, respectively	443	439
Additional paid-in capital	766,875	761,972
Treasury stock held, at cost, 433,399, and 513,426 shares, respectively	(9,686)	(12,575)
Retained earnings	296,831	283,380
Total Stockholders' Equity	1,054,463	1,033,216
Total Liabilities and Stockholders' Equity	$2,724,536	$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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues:				
Oil and gas sales	$158,214	$140,892	$306,772	$287,369
Price-risk management and other, net	(2,493)	1,574	(7,370)	1,334
Total Revenues	155,721	142,466	299,402	288,703
Costs and Expenses:				
General and administrative, net	12,412	11,191	23,151	23,916
Depreciation, depletion, and amortization	72,205	59,458	133,890	119,578
Accretion of asset retirement obligation	1,415	1,479	2,801	3,254
Lease operating cost	21,932	26,957	47,199	54,381
Transportation and gas processing	6,013	4,865	11,305	10,895
Severance and other taxes	9,436	10,501	18,638	20,276
Interest expense, net	18,649	17,000	37,098	33,802
Total Costs and Expenses	142,062	131,451	274,082	266,102
Income Before Income Taxes	13,659	11,015	25,320	22,601
Provision for Income Taxes	5,621	4,293	11,869	8,670
Net Income	$8,038	$6,722	$13,451	$13,931
Per Share Amounts-				
Basic: Net Income	$0.18	$0.15	$0.31	$0.32
Diluted: Net Income	$0.18	$0.15	$0.30	$0.32
Weighted Average Shares Outstanding - Basic	43,826	43,369	43,727	43,268
Weighted Average Shares Outstanding - Diluted	44,312	43,612	44,215	43,599

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 (74,638 shares) (1)	—	—	(896)	—	(896)
Employee stock purchase plan (71,825 shares) (1)	1	823	—	—	824
Issuance of restricted stock (291,561 shares) (1)	3	(3)	—	—	—
Amortization of share-based compensation (1)	—	5,959	—	—	5,959
Net Income (1)	—	—	—	13,451	13,451
Balance, June 30, 2014	$443	$766,875	$(9,686)	$296,831	$1,054,463

(1) Unaudited

See accompanying Notes to Condensed Consolidated Financial Statements.

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

	Six Months Ended June 30, 2014	2013
Cash Flows from Operating Activities:		
Net income	$13,451	$13,931
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion, and amortization	133,890	119,578
Accretion of asset retirement obligation	2,801	3,254
Deferred income taxes	11,869	8,670
Share-based compensation expense	3,953	6,018
Other	(2,439)	(6,024)
Change in assets and liabilities-		
(Increase) decrease in accounts receivable	2,132	601
Increase (decrease) in accounts payable and accrued liabilities	4,852	3,605
Increase (decrease) in income taxes payable	(150)	(178)
Increase (decrease) in accrued interest	(56)	76
Net Cash Provided by Operating Activities	170,303	149,531
Cash Flows from Investing Activities:		
Additions to property and equipment	(208,979)	(265,317)
Proceeds from the sale of property and equipment	35	6,841
Net Cash Used in Investing Activities	(208,944)	(258,476)
Cash Flows from Financing Activities:		
Proceeds from bank borrowings	257,100	568,200
Payments of bank borrowings	(221,100)	(447,600)
Net proceeds from issuances of common stock	824	946
Purchase of treasury shares	(896)	(1,433)
Net Cash Provided by Financing Activities	35,928	120,113
Net increase (decrease) in Cash and Cash Equivalents	(2,713)	11,168
Cash and Cash Equivalents at Beginning of Period	3,277	170
Cash and Cash Equivalents at End of Period	$564	$11,338
Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	$36,031	$32,708
Cash paid during period for income taxes	$150	$178

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. On July 15, 2014, we closed our transaction with PT Saka Energi Indonesia ("Saka Energi") to fully develop 8,300 acres of Fasken area Eagle Ford shale properties owned by Swift Energy in Webb County, Texas. Swift Energy sold a 36% full participating interest in the Fasken properties to Saka Energi for $175 million in total cash consideration, with $125 million paid at closing and $50 million in cash to be paid by Saka Energi over time to carry a portion of Swift Energy's field development costs incurred after the effective date, January 1, 2014.

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.

Property and Equipment. We follow the "full-cost" method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the three months ended June 30, 2014 and 2013, such internal costs capitalized totaled $6.9 million and $7.5 million, respectively. For the six months ended June 30, 2014 and 2013, such internal costs capitalized totaled $14.1 million and $16.0 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the three months ended June 30, 2014 and 2013, capitalized interest on unproved properties totaled $1.2 million and $1.9 million, respectively. For the six months ended June 30, 2014 and 2013, capitalized interest on unproved properties totaled $2.5 million and $3.8 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

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

	June 30, 2014	December 31, 2013
Property and Equipment		
Proved oil and gas properties	$5,817,395	$5,600,279
Unproved oil and gas properties	63,662	71,452
Furniture, fixtures, and other equipment	42,400	42,368
Less – Accumulated depreciation, depletion, and amortization	(3,308,992)	(3,174,453)
Property and Equipment, Net	$2,614,465	$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.

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

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using the preceding 12-months' average price based on closing prices on the first day of each month, adjusted for price differentials, 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 future and that non-cash write-downs of oil and natural gas properties could occur in the future. For example, 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 estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties.

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Swift Energy uses the entitlement method of accounting in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying condensed consolidated balance sheets. Natural gas balancing receivables are reported in "Other current assets" on the accompanying condensed consolidated balance sheets when our ownership share of production exceeds sales. As of June 30, 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 June 30, 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 June 30, 2014, our "Accounts receivable" balance included $59.0 million for oil and gas sales, $1.1 million for joint interest owners, $7.7 million for severance tax credit receivables and $0.8 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 June 30, 2014, was $1.5 million. The 8.875% senior notes due in 2020 mature on January 15, 2020, and the balance of their issuance costs at June 30, 2014, was $3.3 million. The 7.875% senior notes due in 2022 mature on March 1, 2022, and the balance of their issuance costs at June 30, 2014, was $6.2 million. The balance of revolving credit facility issuance costs at June 30, 2014, was $2.9 million.

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. 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.

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During the three months ended June 30, 2014 and 2013, we recorded net losses of $2.7 million and net gains of $1.5 million, respectively, relating to our derivative activities. The 2014 amount includes a revenue reduction of $1.2 million during the second 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 June 30, 2014 was $0.2 million which was recognized on the accompanying condensed consolidated balance sheet in “Other current assets.” The fair value of our unsettled derivative liabilities at June 30, 2014 was $3.1 million which was recognized on the accompanying condensed consolidated balance sheet in “Accounts payable and accrued liabilities.”

At June 30, 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 July 2014. At June 30, 2014, we also had $1.3 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 July 2014.

The Company uses an International Swap and Derivatives Association "ISDA" master agreement for our 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 $2.9 million at June 30, 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 June 30, 2014:

Oil Derivatives (NYMEX WTI Settlements)	Total Volumes (Bbls)	Swap Fixed Price
2014 Contracts		
Swaps	197,500	$ 101.76

Natural Gas Derivatives (NYMEX Henry Hub Settlements)	Total Volumes (MMBtu)	Swap Fixed Price	Collars Floor Price	Ceiling Price
2014 Contracts				
Swaps	7,020,000	$ 4.29		
Collars	2,100,000		$ 4.13	$ 4.46
2015 Contracts				
Swaps	900,000	$ 4.42		

Natural Gas Basis Derivatives (East Texas Houston Ship Channel Settlements)	Total Volumes (MMBtu)	Swap Fixed Price
2014 Contracts		
Swaps	8,850,000	$ (0.09)

2015 Contracts		
Swaps	8,200,000	$ (0.02)

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,

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net", on the accompanying condensed consolidated statements of operations. Our supervision fees are based on COPAS industry guidelines. The amount of supervision fees charged for the three and six months ended June 30, 2014 and 2013 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated were $3.0 million and $3.3 million for the three months ended June 30, 2014 and 2013, respectively and $5.7 million and $6.1 million for the six months ended June 30, 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 $3.0 million and $3.5 million at June 30, 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 June 30, 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 six months ended June 30, 2014, we recognized an income tax expense increase of $1.9 million related to a shortfall between the tax deduction received with respect to prior restricted stock grants that vested during the year 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):

	June 30, 2014	December 31, 2013
Trade accounts payable (1)	$ 39,240	$ 30,769
Accrued operating expenses	15,988	17,059
Accrued payroll costs	8,655	10,938
Asset retirement obligation – current portion	13,717	15,859
Accrued taxes	7,533	5,845
Escrow deposit liability (2)	12,500	—
Other payables	6,890	2,891
Total accounts payable and accrued liabilities	$ 104,523	$ 83,361

(1) Included in "trade accounts payable" are liabilities of approximately $7.5 million and $26.1 million at June 30, 2014 and December 31, 2013, respectively, for outstanding checks.

(2) This amount includes the liability related to the Fasken joint venture for the restricted cash, held in escrow, at June 30, 2014.

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

Restricted Cash. During the second quarter we received a cash deposit, held in an escrow account, of $12.5 million related to the Fasken joint venture. These amounts were contractually restricted until the transaction closed on July 15, 2014. As of June 30, 2014, this balance is reported in “Other current assets” on the accompanying condensed consolidated balance sheets.

Restricted Cash also includes amounts held in escrow accounts to satisfy plugging and abandonment obligations. As of June 30, 2014 and December 31, 2013, these assets were approximately $1.0 million. These amounts are restricted as to their

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current use and will be released when we have satisfied all plugging and abandonment obligations in certain fields. These 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	2,801
Liabilities incurred for new wells and facilities construction	180
Reductions due to sold and abandoned wells and facilities	(2,643)
Revisions in estimates	258
Asset Retirement Obligation as of June 30	$79,680

At June 30, 2014 and December 31, 2013, approximately $13.7 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. In May 2014, the FASB issued ASU 2014-09, providing a comprehensive revenue recognition standard for contracts with customers that supersedes current revenue recognition guidance. The guidance is effective for annual and interim reporting periods beginning after December 15, 2016 and upon adoption, entities are required to recognize revenue using the following five-step model: identify the contract with a customer, identify the performance obligations in the contract, determine the transaction price, allocate the transaction price to the performance obligations in the contract, and recognize revenue as the entity satisfies each performance obligation. Adoption of this standard could result in retrospective application, either in the form of recasting all prior periods presented or a cumulative adjustment to equity in the period of adoption. We plan to review and assess the effect and implement any necessary requirements as needed.

(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 and six months ended June 30, 2014, we recognized an income tax shortfall in earnings of $0.2 million and $1.9 million, respectively, related to restricted stock awards that vested at a price lower than the grant date fair value. For the three and six months ended June 30, 2013, we did not recognize any material excess tax benefit or shortfall in earnings. There were no stock option exercises for the six months ended June 30, 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 $1.7 million and $2.8 million for the three months ended June 30, 2014 and 2013, respectively and $3.6 million and $5.6 million for the six months ended June 30, 2014 and 2013, respectively. Share-based compensation recorded in lease operating cost was less than $0.1 million for the three months ended June 30, 2014 and 2013 and was $0.1 million and $0.2 million for the six months ended June 30, 2014

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and 2013, respectively. We also capitalized $0.9 million and $1.6 million of share-based compensation for the three months ended June 30, 2014 and 2013, respectively, and capitalized $2.0 million and $3.2 million for the six months ended June 30, 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 six months ended June 30, 2014 and 2013 we did not grant any stock option awards.

At June 30, 2014, we had $0.3 million of unrecognized compensation cost related to stock option awards, which is expected to be recognized over a weighted-average period of 0.6 years. The following table represents stock option award activity for the six months ended June 30, 2014:

	Shares	Wtd. Avg. Exercise Price
Options outstanding, beginning of period	1,488,314	$33.38
Options granted	—	$—
Options canceled	(58,694)	$23.24
Options exercised	—	$—
Options outstanding, end of period	1,429,620	$33.78
Options exercisable, end of period	1,327,449	$33.87

Our stock option awards outstanding and exercisable at June 30, 2014 were out of the money and therefore had no aggregate intrinsic value. At June 30, 2014, the weighted average contract life of stock option awards outstanding was 5.0 years and the weighted average contract life of stock option awards exercisable was 4.8 years. There were no stock option exercises for the six months ended June 30, 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 June 30, 2014, we had unrecognized compensation expense of $14.9 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 six months ended June 30, 2014 was $10.2 million.

The following table represents restricted stock award activity for the six months ended June 30, 2014:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	1,267,110	$21.54
Restricted shares granted	716,650	$11.57
Restricted shares canceled	(114,672)	$15.37
Restricted shares vested	(291,561)	$34.83

Restricted shares outstanding, end of period	1,577,527	$ 15.00

Performance-Based Restricted Stock Units

For the six months ended June 30, 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

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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.

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 June 30, 2014, we had unrecognized compensation expense of $3.1 million related to our restricted stock units which is expected to be recognized over a weighted-average period of 2.3 years. No shares vested during the six months ended June 30, 2014 and 2013. The weighted average grant date fair value for the restricted stock units granted during the six months ended June 30, 2014 and 2013 was $11.68 and $15.01 per unit, respectively.

The following table represents restricted stock unit activity for the six months ended June 30, 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 and six months ended June 30, 2014 and 2013, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the three and six months ended June 30, 2014 and 2013 (in thousands, except per share amounts):

	Three Months Ended June 30, 2014			Three Months Ended June 30, 2013		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$ 8,038	43,826	$ 0.18	$ 6,722	43,369	$ 0.15
Dilutive Securities:						
Stock Options		—			—	
Restricted Stock Awards		429			192	
Restricted Stock Units		57			51	
Diluted EPS:						
Net Income and Assumed Share Conversions	$ 8,038	44,312	$ 0.18	$ 6,722	43,612	$ 0.15

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	Six Months Ended June 30, 2014			Six Months Ended June 30, 2013		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$13,451	43,727	$0.31	$13,931	43,268	$0.32
Dilutive Securities:						
Stock Options		—			2	
Restricted Stock Awards		424			242	
Restricted Stock Units		64			87	
Diluted EPS:						
Net Income and Assumed Share Conversions	$13,451	44,215	$0.30	$13,931	43,599	$0.32

Approximately 1.4 million and 1.6 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months ended June 30, 2014 and 2013, respectively, and approximately 1.5 million stock options to purchase shares were not included in the computation of Diluted EPS for the six months ended June 30, 2014 and 2013 because these stock options were antidilutive. Approximately 0.3 million restricted stock awards were not included in the computation of Diluted EPS for the three and six months ended June 30, 2014 and 2013 because they were antidilutive. Approximately 0.7 million and 0.3 million shares for three and six months ended June 30, 2014 and 2013, respectively, 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 because the performance and market conditions had not been met, assuming the end of the reporting period was the end of the performance period.

(5) Long-Term Debt

Our long-term debt as of June 30, 2014 and December 31, 2013, was as follows (in thousands):

	June 30, 2014	December 31, 2013
7.125% senior notes due in 2017	$250,000	$250,000
8.875% senior notes due in 2020 (1)	222,607	222,446
7.875% senior notes due in 2022 (1)	404,694	404,922
Bank Borrowings due in 2017	301,000	265,000
Long-Term Debt (1)	$1,178,301	$1,142,368

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

As of June 30, 2014, we had $301.0 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 $1.2 million and $1.9 million for the three months ended June 30, 2014 and 2013, respectively, and we have capitalized interest on our unproved properties in the amount of $2.5 million and $3.8 million for the six months ended June 30, 2014 and 2013, respectively.

Bank Borrowings. Due to the closing of our recent Fasken joint venture transaction with Saka Energi, our syndicate of 11 banks automatically reduced the borrowing base and commitment amount from $450.0 million to $417.6 million on our $500.0 million credit facility, effective July 15, 2014. The maturity date of November 1, 2017 remained unchanged.

We had $301.0 million and $265.0 million in outstanding borrowings under our credit facility at June 30, 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 June 30, 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 June 30, 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 June 30, 2014 and 2013, respectively. Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $4.2 million and $2.4 million for the six months ended June 30, 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 June 30, 2014 and 2013, respectively, and was $0.3 million and $0.6 million for the six months ended June 30, 2014 and 2013.

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 June 30, 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 June 30, 2014 and 2013 and $15.8 million for the six months ended June 30, 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

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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 June 30, 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 June 30, 2014 and 2013 and $10.4 million and $10.3 million for the six months ended June 30, 2014 and 2013, respectively.

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 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 June 30, 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 June 30, 2014 and 2013 and $9.1 million for the six months ended June 30, 2014 and 2013.

(6) Acquisitions and Dispositions

Effective May 1, 2013, we disposed of our Brookeland field in Texas and received net cash proceeds of $5.8 million. This disposition also included the buyer's assumption of our plugging and abandonment liability that was previously included as $11.3 million in "Asset Retirement Obligation" on the accompanying condensed consolidated balance sheets.
There were no material acquisitions or dispositions for the six months ended June 30, 2014.

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

Based upon quoted market prices as of June 30, 2014 and December 31, 2013, the fair value and carrying value of our senior notes was as follows (in millions):

	June 30, 2014		December 31, 2013	
	Fair Value	Carrying Value	Fair Value	Carrying Value
7.125% senior notes due in 2017	$ 253.8	$ 250.0	$ 256.7	$ 250.0
8.875% senior notes due in 2020	$ 239.6	$ 222.6	$ 239.1	$ 222.4
7.875% senior notes due in 2022	$ 422.0	$ 404.7	$ 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 June 30, 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)
June 30, 2014				
Assets:				
Natural Gas Derivatives	$0.2	$—	$0.2	$—
Liabilities:				
Natural Gas Derivatives	1.6	—	1.6	—
Gas Basis Derivatives	0.9	—	0.9	—
Oil Derivatives	0.6	—	0.6	—
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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(9) Commitments and Contingencies

During the second quarter of 2014, the Company entered into additional gas transportation agreements. Minimum commitments under these agreements total approximately $37.0 million covering transportation from 2015 through 2020.

We had no other material changes from amounts referenced under Note 5 in our Notes to Consolidated Financial Statements from our Annual Report on Form 10-K for the year ending December 31, 2013.

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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 28 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 26% of our second quarter 2014 production and 57% of our oil and gas sales, and combined production of both oil and natural gas liquids ("NGLs") constituted 38% of our second quarter 2014 production and 66% of our oil and gas sales. In recent periods, this has allowed us to benefit from better margins for oil production, as oil prices are significantly higher on a Boe basis than natural gas prices.

Second Quarter 2014 Activities

- Production: Our production volumes increased by 24% in the second quarter of 2014 when compared to volumes in the same period in 2013 as natural gas production volumes increased by 61%, while oil volumes decreased by 2% and NGL volumes decreased by 21% . Sequentially, production volumes increased by 17% in the second quarter of 2014 compared to first quarter of 2014 levels as natural gas production volumes increased by 38%, oil volumes decreased by 4% and NGL volumes decreased by 9%. For both of the comparisons noted above, the majority of the change in oil production volumes was attributable to operations in our Southeast Louisiana areas while the majority of the change in NGL and natural gas volumes was primarily from our South Texas area.

- Pricing: Our weighted average sales price in the second quarter of 2014 decreased by 10% when compared to average price levels in the second quarter of 2013. When compared to pricing in the second quarter of 2013, oil prices in the second quarter of 2014 decreased 1%, NGL prices increased 14% and natural gas prices increased 8%. Sequentially, when comparing second quarter of 2014 pricing to pricing in the first quarter of 2014, oil prices increased 2%, NGL prices decreased 6% and natural gas prices decreased 1%.

- Cash provided by operating activities: For the first six months of 2014, our cash provided by operating activities increased by $20.8 million or 14%, when compared to levels in the first six months of 2013, due primarily to an increase in oil and gas revenues in the 2014 period driven by higher natural gas production volumes and prices.

- Outstanding Bank Borrowings: At June 30, 2014, we had $301.0 million in outstanding borrowings under our credit facility. Our borrowing base and commitment amount under the credit facility at June 30, 2014 was $450.0 million. Pursuant to the terms of our credit facility, the previously announced closing of our Fasken joint venture with Saka Energi on July 15, 2014 automatically reduced our borrowing base and commitment amount to $417.6 million. The proceeds of approximately $147 million received at closing were immediately used to pay down our outstanding borrowing under the credit facility. We plan to utilize amounts received from any further asset sales or joint ventures entered into to strengthen our balance sheet and enhance our liquidity.

- 2014 capital expenditures: Our capital expenditures on a cash flow basis were $209.0 million in the first six months of 2014, compared to $265.3 million in the first six months of 2013. The expenditures were devoted to drilling and completion activity in our South Texas core region as we drilled 13 wells in our AWP Eagle Ford field and nine wells in our Fasken field. These expenditures were funded by $170.3 million of cash provided by operating activities and the remainder through borrowings under our credit facility.

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Strategy and Outlook

- Eagle Ford Joint Venture with Saka Energi: As previously announced, on July 15, 2014, we closed a joint venture transaction with Saka Energi to fully develop 8,300 acres of natural gas Eagle Ford shale properties in our Fasken area. Saka Energi purchased a 36% full participating interest in the properties for $175 million in total cash consideration, with $125 million paid at closing and $50 million in cash to be paid by Saka Energi over time to carry a portion of Swift Energy's field development costs incurred after the effective date, January 1, 2014. After closing, approximately $38 million remains of Saka’s original $50 million drilling carry obligation, which is expected to be fulfilled by the end of calendar year 2016. At closing, Swift received approximately $147 million, composed of the initial $125 million in cash consideration plus Saka Energi's share of capital costs, net of revenue between the January 1, 2014 effective date and the closing. We expect this joint venture to allow an overall accelerated drilling and development program of our Fasken properties.

- Fasken Production: In Fasken, we have grown our Eagle Ford dry gas gross production from 28.3 million cubic feet of gas per day (“MMcf/d”) during the second quarter of 2013 to 103.8 MMcf/d during the second quarter of 2014, a 367% increase. We have contracted firm transportation capacity of 75 MMcf/d and have also been able to access interruptible capacity in excess of that amount during the second quarter of 2014. We have also contracted for an increase in this firm transportation capacity to 160 MMcf/d, which we currently expect to be available by early next year. We currently expect to reach this daily production level by early 2015. In the meantime, we expect to have access to some interruptible capacity for the remainder of 2014, but unlikely at a level as high as that available in the second quarter. Although we believe that we should be able to access some interruptible capacity during the remainder of the year, it is difficult to accurately forecast the amount that might be available and whether or not transportation availability will be a limiting factor on our Fasken production from time to time during the last half of 2014.

- Full Year 2014 Planned Capital Expenditures: Following the closing of our Fasken joint venture, our 2014 planned capital expenditures are $375 to $400 million, an increase from our most recent full-year estimates of $350 to $400 million. We currently plan to fund our 2014 capital expenditures with our operating cash flow along with a portion of the proceeds received from the recently closed Saka Energi transaction. The remaining portion of the proceeds from the Saka Energi transaction was used to pay down our credit facility. For 2014, the Company is targeting annual production levels of 11.9 to 12.1 MMBoe based on the above spending levels.

- Reduced Spending for 2014: We are planning a reduced overall level of capital spending for 2014, compared to the prior year, to levels more in line with our internally generated cash flow and some portion of the Saka Energi joint venture proceeds. Our priorities for 2014 continue to be financial discipline first and growth second. We expect to continue focusing on South Texas production and reserves growth, while maintaining a stronger balance sheet. 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.

- Central Louisiana Properties: We continue to work with a prospective buyer for all of our Central Louisiana properties, but we are uncertain when or if this transaction will occur. At this point, if no sale of these assets were to occur, we anticipate investing a limited amount of capital in 2015 in low risk projects to maintain the value of these assets, while evaluating future alternatives.

- 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. We have been successful at utilizing these enhanced targeting techniques in the

Eagle Ford formation and conducting “engineered” completions in our wells in our Fasken field, North AWP as well as the joint venture area in the central portion of AWP, proving the transferability of this technology. 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, we have increased the number of frac stages per 1,000 feet of lateral length and are using greater amounts of proppant with each frac as we believe these changes could bring further improvement in our results. We have also seen improved performance in our multi-staged

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completions when the stages are “engineered” for placement in the optimal areas of the formation, compared to completions where the stages were spaced geometrically.

- 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 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 observed excellent production results from our recently completed wells in our Fasken area this year, 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 has 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 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 utilized additional 3D seismic data over the southern area at Lake Washington and will be 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, as well as our liquids-rich areas.

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Results of Operations

Revenues — Three Months Ended June 30, 2014 and 2013

Our oil and gas sales in the second quarter of 2014 increased by 12% compared to oil and gas sales in the second quarter of 2013, primarily due to higher natural gas production, partially offset by lower oil and NGL production. Average oil prices we received were 1% lower than those received during the second quarter of 2013, while natural gas prices were 8% higher and NGL prices were 14% higher.

Crude oil production was 26% and 33% of our production volumes in the second quarters of 2014 and 2013, respectively. Crude oil sales were 57% and 67% of oil and gas sales in the second quarters of 2014 and 2013, respectively. Natural gas production was 62% and 47% of our production volumes in the second quarters of 2014 and 2013, respectively. Natural gas sales were 33% and 22% of oil and gas sales in the second quarters of 2014 and 2013, respectively. The remaining production and sales in each period came from NGLs.

The following table provides additional information regarding our oil and gas sales, excluding any effects of our hedging activities, for the three months ended June 30, 2014 and 2013:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2014	2013	2014	2013
Southeast Louisiana	$ 34.2	$ 43.8	367	462
South Texas	112.6	85.6	2,916	2,123
Central Louisiana	10.8	11.3	158	192
Other	0.6	0.2	8	1
Total	$ 158.2	$ 140.9	3,449	2,778

In the second quarter of 2014, our $17.3 million, or 12% increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $4.2 million favorable impact on sales, with an increase of $3.7 million attributable to the 8% increase in natural gas prices, a decrease of $1.3 million due to the 1% decrease in average oil prices received and an increase of $1.8 million due to the 14% increase in NGL prices.
- Volume variances that had a $13.1 million favorable impact on sales, with a $2.2 million decrease due to a less than 0.1 million Bbl decrease in oil production volumes, a $3.4 million decrease attributable to the 0.1 million Bbl decrease in NGL production volumes and an $18.7 million increase due to the 4.8 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 June 30, 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 June 30, 2014	890	434	12.7	3,449	$ 101.67	$ 33.93	$ 4.16
Three Months Ended June 30, 2013	911	549	7.9	2,778	$ 103.15	$ 29.74	$ 3.86

For the three months ended June 30, 2014 and 2013, we recorded total net (losses) gains of ($2.7 million) and $1.5 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 $100.16 and $102.84 for the second quarters of 2014 and 2013, respectively, and our average natural gas price would have been $4.05 and $4.09 for the second quarters of 2014 and 2013, respectively.

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Costs and Expenses — Three Months Ended June 30, 2014 and 2013

Our expenses in the second quarter of 2014 increased $10.6 million, or 8%, compared to those in the second quarter of 2013, for the reasons noted below.

Lease operating cost. These expenses decreased $5.0 million, or 19%, compared to the level of such expenses in the second quarter of 2013. While our cost savings initiatives are beginning to be realized (such as the cost decreases in South Texas for lower salt water disposal costs), this quarter's large decrease was primarily the result of previously estimated and accrued expenses being greater than actual costs incurred. Our lease operating costs per Boe produced were therefore $6.36 and $9.70 for the three months ended June 30, 2014 and 2013, respectively, with the per unit decline being the result of higher volumes and lower total expense in the current quarter.

Transportation and gas processing. These expenses increased $1.1 million, or 24%, compared to the level of such expenses in the second quarter of 2013 as our natural gas production volumes increased 61%. Our transportation and gas processing costs per Boe produced were $1.74 and $1.75 for the second quarters of 2014 and 2013, respectively.

Depreciation, Depletion and Amortization ("DD&A"). These expenses increased $12.7 million, or 21% from those in the second 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 was $20.93 and $21.40 in the second quarters of 2014 and 2013, respectively.

General and Administrative Expenses, Net. These expenses increased $1.2 million, or 11%, from the level of such expenses in the second quarter of 2013. The increase was primarily due a higher corporate benefit accrual, higher legal & professional fees and lower capitalized costs, partially offset by lower deferred compensation and lower salaries. For the second quarters of 2014 and 2013, our capitalized general and administrative costs totaled $6.9 million and $7.5 million, respectively. Our net general and administrative expenses per Boe produced decreased to $3.60 per Boe in the second quarter of 2014 from $4.03 per Boe in the second quarter of 2013. The supervision fees recorded as a reduction to general and administrative expenses were $3.0 million and $3.3 million for the second quarters of 2014 and 2013, respectively.

Severance and Other Taxes. These expenses decreased $1.1 million, or 10%, from second quarter 2013 levels. Severance and other taxes, as a percentage of oil and gas sales, were approximately 6.0% and 7.5% in the second quarters of 2014 and 2013, respectively. The decrease in the rate was primarily driven by higher production in South Texas which carries a lower severance tax rate than Louisiana.

Interest. Our gross interest cost in the second quarter of 2014 was $19.9 million, of which $1.2 million was capitalized. Our gross interest cost in the second quarter of 2013 was $18.9 million, of which $1.9 million was capitalized. The increase came primarily from additional borrowings on our credit facility as well as a decrease in capitalized interest due to a lower unproved properties balance.

Income Taxes. Our effective income tax rate was 41.2% and 39.0% for the second quarters of 2014 and 2013, respectively.

Revenues — Six Months Ended June 30, 2014 and 2013

Our oil and gas sales for the first six months of 2014 increased by 7% compared to oil and gas sales in the first six months of 2013, primarily due to higher natural gas pricing and production, partially offset by lower oil pricing and production. Average oil prices we received were 5% lower than those received during the first six months of 2013, while natural gas prices were 22% higher and NGL prices were 18% higher.

Crude oil production was 28% and 34% of our production volumes in the six months ended June 30, 2014 and 2013, respectively. Crude oil sales were 60% and 70% of oil and gas sales in the six months ended June 30, 2014 and 2013, respectively. Natural gas production was 57% and 46% of our production volumes in the six months ended June 30, 2014 and 2013, respectively. Natural gas sales were 30% and 19% of oil and gas sales in the six months ended June 30, 2014 and 2013, respectively. The remaining production and sales in each period came from NGLs.

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The following table provides additional information regarding our oil and gas sales, excluding any effects of our hedging activities, for the six months ended June 30, 2014 and 2013:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2014	2013	2014	2013
Southeast Louisiana	$71.4	$87.8	768	908
South Texas	212.0	172.2	5,265	4,228
Central Louisiana	22.4	26.6	344	441
Other	1.0	0.8	17	20
Total	$306.8	$287.4	6,394	5,597

During the first six months of 2014, our 19.4 million, or 7% increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $11.5 million favorable impact on sales, with an increase of $16.5 million attributable to the 22% increase in natural gas prices, a decrease of $9.9 million due to the 5% decrease in average oil prices received and an increase of $4.9 million due to the 18% increase in NGL prices.
- Volume variances that had a $7.8 million favorable impact on sales, with a $8.3 million decrease due to the 0.1 million Bbl decrease in oil production volumes, a $5.8 million decrease attributable to the 0.2 million Bbl decrease in NGL production volumes and a $21.9 million increase due to the 6.4 Bcf increase in natural gas production volumes.

The following table provides additional information regarding our quarterly oil and gas sales, excluding any effects of our hedging activities, for the six months ended June 30, 2014 and 2013:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Six Months Ended June 30, 2014	1,821	913	22.0	6,394	$100.50	$35.16	$4.17
Six Months Ended June 30, 2013	1,900	1,106	15.5	5,597	$105.91	$29.83	$3.42

For the six months ended June 30, 2014 and 2013, we recorded total net (losses) gains of ($7.8 million) and $1.2 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 $99.27 and $105.73 for the six months ended June 30, 2014 and 2013, respectively, and our average natural gas price would have been $3.92 and $3.52 for the six months ended June 30, 2014 and 2013, respectively.

Costs and Expenses — Six Months Ended June 30, 2014 and 2013

Our expenses for the first six months of 2014 increased $8.0 million, or 3%, compared to those in the first six months of 2013, for the reasons noted below.

Lease operating cost. These expenses decreased $7.2 million, or 13%, compared to the level of such expenses in the first six months of 2013. While our cost savings initiatives are beginning to be realized, this decrease is larger than normal due to a reduction in 2014 for previously estimated and accrued expenses being greater than actual costs incurred and the one-time costs associated with a well control incident in Lake Washington during the first half of 2013. Our lease operating costs per Boe produced were $7.38 and $9.72 for the six months ended June 30, 2014 and 2013, respectively, with the per unit decline being the result of higher volumes and lower total expense in the current period.

Transportation and gas processing. These expenses increased $0.4 million, or 4%, compared to the level of such expenses in the first six months of 2013. Our transportation and gas processing costs per Boe produced were $1.77 and $1.95 for the six months ended June 30, 2014 and 2013, respectively.

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Depreciation, Depletion and Amortization (“DD&A”). These expenses increased $14.3 million, or 12% from those in the first six months of 2013. The increase was due to higher production and a higher depletable base including higher future development costs. Our DD&A rate per Boe of production improved to $20.94 for the six months ended June 30, 2014, as compared to $21.36 for the six months ended June 30, 2013.

General and Administrative Expenses, Net. These expenses decreased $0.8 million, or 3%, from the level of such expenses in the first six months of 2013. The decrease was primarily due to lower salaries and lower deferred compensation, partially offset by lower capitalized amounts and higher legal and professional fees. For the six months ended June 30, 2014 and 2013, our capitalized general and administrative costs totaled $14.1 million and $16.0 million, respectively. Our net general and administrative expenses per Boe produced decreased to $3.62 per Boe in the first six months of 2014 from $4.27 per Boe in the first six months of 2013. The supervision fees recorded as a reduction to general and administrative expenses were $5.7 million and $6.1 million for the six months ended June 30, 2014 and 2013, respectively.

Severance and Other Taxes. These expenses decreased $1.6 million, or 8%, from first six months of 2013 levels. Severance and other taxes, as a percentage of oil and gas sales, were approximately 6.1% and 7.1% in the six months ended June 30, 2014 and 2013, respectively. The decrease in the rate was primarily driven by higher production in South Texas which carries a lower severance tax rate than Louisiana.

Interest. Our gross interest cost in the first six months of 2014 was $39.6 million, of which $2.5 million was capitalized. Our gross interest cost in the first six months of 2013 was $37.6 million, of which $3.8 million was capitalized. The increase came primarily from additional borrowings on our credit facility as well as a decrease in capitalized interest due to a lower unproved properties balance.

Income Taxes. Our effective income tax rate was 46.9% and 38.4% for the six months ended June 30, 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 during the year 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 six months of 2014, our net cash provided by operating activities was $170.3 million, representing a 14% increase compared to $149.5 million generated during the same period of 2013. The increase was due primarily to an increase in oil and gas revenues driven by higher natural gas production volumes and prices.

Working Capital and Debt to Capitalization Ratio. Our working capital decreased from a deficit of $90.3 million at December 31, 2013, to a deficit of $92.0 million at June 30, 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 June 30, 2014 and December 31, 2013.

Existing Credit Facility. At June 30, 2014, we had $301.0 million in outstanding borrowings under our credit facility. Our borrowing base and commitment amount were automatically reduced from $450.0 million to $417.6 million effective July 15, 2014, due to the Fasken Joint Venture with Saka Energi. We used the proceeds from this transaction to reduce our outstanding borrowings on our credit facility, lowering our leverage and enhancing our liquidity. The completion of this transaction also allows us to better align our capital expenditures with our expected cash flows. The next scheduled borrowing base redetermination occurs in November 2014.

Contractual Commitments and Obligations

During the second quarter of 2014, the Company entered into additional gas transportation agreements. Minimum commitments under these agreements total approximately $37.0 million as follows: 2015 - $6.5 million, 2016 - $7.7 million, 2017 - $7.0 million, 2018 - $6.5 million and $9.3 million thereafter.

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

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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 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 change in the future and that non-cash write-downs of oil and natural gas properties could occur in the future. For example, 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 estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties.

New Accounting Pronouncements. In May 2014, the FASB issued ASU 2014-09 which provides a single, comprehensive revenue recognition model for all contracts with customers across various industries. The guidance is effective for annual and interim reporting periods beginning after December 15, 2016. We plan to review and assess the effect and implement any necessary requirements as needed.

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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:

- the amount, nature and timing of capital expenditures, including future development costs;
- timing and amount of future production of oil and natural gas
- business strategy, financial strategy, budget, projections and operating results;
- estimated oil and natural gas reserves or the present value thereof;
- technology;
- our borrowing capacity, cash flows and liquidity;
- 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 June 30, 2014, we had $301.0 million drawn under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank’s base rate would constitute 33 basis points and would not have a material adverse effect on our future cash flows.

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Item 4. Controls and Procedures

Disclosure Controls and Procedures

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

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the first six months of 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 second 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)
04/01/14 – 04/30/14 (1)	1,700	$ 11.51	—	$—
05/01/14 – 05/31/14 (1)	847	$ 11.02	—	—
06/01/14 – 06/30/14 (1)	979	$ 12.31	—	—
Total	3,526	$ 11.62	—	$—

(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.

None.

Item 6. Exhibits.

10.1	Amendment No. 1 to the Second Amended and Restated Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May 27, 2014, File No. 1-08754).
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101.INS*	XBRL Instance Document
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: August 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

10.1	Amendment No. 1 to the Second Amended and Restated Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May 27, 2014, File No. 1-08754).
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
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