SWIFT ENERGY CO
Form 10-Q
November 03, 2011

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

FORM 10-Q

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

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.
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) | 42,478,426 Shares |
| (Class of Stock) | (Outstanding at October 31, 2011) |

SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2011

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

| | September 30, 2011 (Unaudited) | December 31, 2010 |
|---|---|---|
| ASSETS | | |
| Current Assets: | | |
| Cash and cash equivalents | $15,999 | $86,367 |
| Accounts receivable | 45,100 | 46,975 |
| Deferred tax asset | 4,826 | 6,347 |
| Other current assets | 10,712 | 18,105 |
| Assets held for sale | --- | 564 |
| Total Current Assets | 76,637 | 158,358 |
| | | |
| Property and Equipment: | | |
| Property and Equipment | 4,376,222 | 3,951,107 |
| Less – Accumulated depreciation, depletion, and amortization | (2,540,613) | (2,378,262) |
| Property and Equipment, Net | 1,835,609 | 1,572,845 |
| | | |
| Other Long-Term Assets | 12,222 | 12,713 |
| Total Assets | $1,924,468 | $1,743,916 |
| | | |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | |
| Current Liabilities: | | |
| Accounts payable and accrued liabilities | $90,751 | $75,594 |
| Accrued capital costs | 82,593 | 64,879 |
| Accrued interest | 10,223 | 11,010 |
| Undistributed oil and gas revenues | 4,010 | 5,252 |
| Total Current Liabilities | 187,577 | 156,735 |
| | | |
| Long-Term Debt | 471,809 | 471,624 |
| Deferred Income Taxes | 192,131 | 157,565 |
| Asset Retirement Obligation | 91,237 | 70,171 |
| Other Long-Term Liabilities | 10,221 | 7,804 |
| | | |
| Commitments and Contingencies | | |
| | | |
| Stockholders' Equity: | | |
| Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding | --- | --- |
| Common stock, $.01 par value, 150,000,000 shares authorized, 42,955,730 and 42,440,583 shares issued, and 42,473,911 and 41,999,058 shares outstanding, respectively | 430 | 424 |
| Additional paid-in capital | 722,502 | 706,857 |
| Treasury stock held, at cost, 481,819 and 441,525 shares, respectively | (12,276) | (9,778) |
| Retained earnings | 260,837 | 182,652 |
| Accumulated other comprehensive income (loss), net of income tax | --- | (138) |
| Total Stockholders' Equity | 971,493 | 880,017 |

| | | |
|---|---|---|
| Total Liabilities and Stockholders' Equity | $1,924,468 | $1,743,916 |

See accompanying Notes to Condensed Consolidated Financial Statements.

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

| | Three Months Ended September 30, | | Nine months Ended September 30, | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Revenues: | | | | |
| Oil and gas sales | $143,123 | $105,811 | $446,537 | $320,887 |
| Price-risk management and other, net | (591) | (165) | (2,499) | 1,505 |
| Total Revenues | 142,532 | 105,646 | 444,038 | 322,392 |
| | | | | |
| Costs and Expenses: | | | | |
| General and administrative, net | 11,378 | 8,722 | 32,687 | 26,010 |
| Depreciation, depletion, and amortization | 54,404 | 40,800 | 163,141 | 118,103 |
| Accretion of asset retirement obligation | 1,183 | 998 | 3,482 | 2,927 |
| Lease operating cost | 26,206 | 20,977 | 78,296 | 59,561 |
| Severance and other taxes | 13,527 | 10,830 | 39,223 | 34,043 |
| Interest expense, net | 8,439 | 8,264 | 25,449 | 24,804 |
| Total Costs and Expenses | 115,137 | 90,591 | 342,278 | 265,448 |
| | | | | |
| Income from Continuing Operations Before Income Taxes | 27,395 | 15,055 | 101,760 | 56,944 |
| | | | | |
| Provision for Income Taxes | 10,388 | 5,652 | 37,822 | 20,788 |
| | | | | |
| Income from Continuing Operations | 17,007 | 9,403 | 63,938 | 36,156 |
| | | | | |
| Income (Loss) from Discontinued Operations, net of taxes | (31) | (73) | 14,247 | (162) |
| | | | | |
| Net Income | $16,976 | $9,330 | $78,185 | $35,994 |
| | | | | |
| Per Share Amounts- | | | | |
| | | | | |
| Basic: Income from Continuing Operations | $0.39 | $0.24 | $1.48 | $0.94 |
| Income (Loss) from Discontinued Operations, net of taxes | (0.00) | (0.00) | 0.33 | (0.00) |
| Net Income | $0.39 | $0.24 | $1.81 | $0.93 |
| | | | | |
| Diluted: Income from Continuing Operations | $0.39 | $0.24 | $1.47 | $0.93 |
| Income (Loss) from Discontinued Operations, net of taxes | (0.00) | (0.00) | 0.33 | (0.00) |
| Net Income | $0.39 | $0.24 | $1.80 | $0.93 |
| | | | | |
| Weighted Average Shares Outstanding - Basic | 42,470 | 37,880 | 42,365 | 37,792 |

See accompanying Notes to Condensed Consolidated Financial statements.

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

| | Common Stock (1) | Additional Paid-in Capital | Treasury Stock | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|---|
| Balance, December 31, 2009 | $379 | $551,606 | $(9,221) | $136,358 | $ (223) | $678,899 |
| | | | | | | |
| Stock issued for benefit plans (59,335 shares) | - | 242 | 1,271 | - | - | 1,513 |
| Stock options exercised (136,432 shares) | 1 | 2,086 | - | - | - | 2,087 |
| Public Stock offering (4,038,270 shares) | 40 | 140,099 | - | - | - | 140,139 |
| Purchase of treasury shares (70,337 shares) | - | - | (1,828) | - | - | (1,828) |
| Tax benefits from share-based compensation | - | 28 | - | - | - | 28 |
| Employee stock purchase plan (66,564 shares) | 1 | 950 | - | - | - | 951 |
| Issuance of restricted stock (312,191 shares) | 3 | (3) | - | - | - | - |
| Amortization of share-based compensation | - | 11,849 | - | - | - | 11,849 |
| Net Income | - | - | - | 46,294 | - | 46,294 |
| Other comprehensive income | - | - | - | - | 85 | 85 |
| Total comprehensive income | | | | | | 46,379 |
| Balance, December 31, 2010 | $424 | $706,857 | $(9,778) | $182,652 | $ (138) | $880,017 |
| | | | | | | |
| Stock issued for benefit plans (37,068 shares) (2) | - | 791 | 821 | - | - | 1,612 |
| Stock options exercised (128,502 shares) (2) | 1 | 1,101 | - | - | - | 1,102 |
| Purchase of treasury shares (77,362 shares) | - | - | (3,319) | - | - | (3,319) |
| Tax benefits from share-based compensation (2) | - | 329 | - | - | - | 329 |
| Employee stock purchase plan (49,089 shares) (2) | 1 | 999 | - | - | - | 1,000 |
| Issuance of restricted stock (337,556 shares) (2) | 4 | (4) | - | - | - | - |
| Amortization of share-based compensation (2) | - | 12,429 | - | - | - | 12,429 |
| Net Income (2) | - | - | - | 78,185 | - | 78,185 |
| Other comprehensive Income (2) | - | - | - | - | 138 | 138 |
| | | | | | | 78,323 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total comprehensive income (2) | | | | | | |
| Balance, September 30, 2011 (2) | $430 | $722,502 | $(12,276 ) | $260,837 | $ --- | $971,493 |

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

See accompanying Notes to Condensed Consolidated Financial Statements.

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

| (in thousands) | Nine months Ended September 30, 2011 | 2010 |
|---|---|---|
| Cash Flows from Operating Activities: | | |
| Net income | $78,185 | $35,994 |
| Plus loss (Less income) from discontinued operations, net of taxes | (14,247) | 162 |
| Adjustments to reconcile net income to net cash provided by operating activities - | | |
| Depreciation, depletion, and amortization | 163,141 | 118,103 |
| Accretion of asset retirement obligation | 3,482 | 2,927 |
| Deferred income taxes | 36,332 | 26,151 |
| Stock-based compensation expense | 9,281 | 7,550 |
| Other | (1,410) | 473 |
| Change in assets and liabilities- | | |
| Decrease in accounts receivable | 6,694 | 1,837 |
| Increase (decrease) in accounts payable and accrued liabilities | 8,077 | (5,812) |
| Decrease in income taxes payable | (234) | (38) |
| Increase (decrease) in accrued interest | (787) | 6,394 |
| Cash provided by operating activities – continuing operations | 288,514 | 193,741 |
| Cash provided by (used in) operating activities – discontinued operations | 5 | (29) |
| Net Cash Provided by Operating Activities | 288,519 | 193,712 |
| | | |
| Cash Flows from Investing Activities: | | |
| Additions to property and equipment | (368,754) | (228,379) |
| Proceeds from the sale of property and equipment | 6,084 | 133 |
| Cash used in investing activities – continuing operations | (362,670) | (228,246) |
| Cash provided by investing activities – discontinued operations | 5,000 | 5,000 |
| Net Cash Used in Investing Activities | (357,670) | (223,246) |
| | | |
| Cash Flows from Financing Activities: | | |
| Net proceeds from issuances of common stock | 2,102 | 1,829 |
| Purchase of treasury shares | (3,319) | (1,775) |
| Payment of debt issuance costs | --- | (3,481) |
| Cash used in financing activities – continuing operations | (1,217) | (3,427) |
| Cash provided by financing activities – discontinued operations | --- | --- |
| Net Cash Used in Financing Activities | (1,217) | (3,427) |
| | | |
| Net Decrease in Cash and Cash Equivalents | (70,368) | (32,961) |
| | | |
| Cash and Cash Equivalents at Beginning of Period | 86,367 | 38,469 |
| | | |
| Cash and Cash Equivalents at End of Period | $15,999 | $5,508 |
| | | |
| Supplemental Disclosures of Cash Flows Information: | | |
| Cash paid during period for interest, net of amounts capitalized | $24,693 | $17,521 |
| Cash paid during period for income taxes | $1,770 | $168 |

See accompanying Notes to Condensed Consolidated Financial Statements.

Notes to Condensed Consolidated Financial Statements
Swift Energy Company and Subsidiaries

(1) General Information

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

(2) Summary of Significant Accounting Policies

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

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

Subsequent Events. We have evaluated subsequent events of our condensed consolidated financial statements. In October 2011, we closed the sale of certain properties located in Louisiana, Texas and Alabama. Please see Note 7 for more information regarding this sale. There were no other material subsequent events requiring additional disclosure in these financial statements.

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

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- estimates related to the collectability of accounts receivable and the credit worthiness of our customers,
- estimates of the counterparty bank risk related to letters of credit that our customers may have issued on our behalf,
- estimates of future costs to develop and produce reserves,
- accruals related to oil and gas sales, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage, and the solvency of insurance providers,
- estimates in the calculation of share-based compensation expense,

- estimates of our ownership in properties prior to final division of interest determination,
- the estimated future cost and timing of asset retirement obligations,
- estimates made in our income tax calculations, and
- estimates in the calculation of the fair value of hedging assets.

While we are not aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as new accounting pronouncements, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

Property and Equipment. We follow the "full-cost" method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the nine months ended September 30, 2011 and 2010, such internal costs capitalized totaled $21.9 million and $17.8 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the nine months ended September 30, 2011 and 2010, capitalized interest on unproved properties totaled $5.7 million and $5.5 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) | September 30, 2011 | December 31, 2010 |
|---|---|---|
| Property and Equipment | | |
| Proved oil and gas properties | $ 4,259,439 | $ 3,835,173 |
| Unproved oil and gas properties | 79,439 | 78,429 |
| Furniture, fixtures, and other equipment | 37,344 | 37,505 |
| Less – Accumulated depreciation, depletion, and amortization | (2,540,613) | (2,378,262) |
| Property and Equipment, Net | $ 1,835,609 | $ 1,572,845 |

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

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

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

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

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using the preceding 12-months' average price based on closing prices on the first day of each month, adjusted for price differentials and the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). Our hedges at December 31, 2010 consisted of oil and natural gas price floors that did not materially affect prices used in these calculations, while we had no hedges in place at September 30, 2011. This calculation is done on a country-by-country basis.

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

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

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Swift Energy uses the entitlement method of accounting in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying condensed consolidated balance sheets. Natural gas balancing receivables are reported in "Other current assets" on the accompanying condensed consolidated balance sheets when our ownership share of production exceeds sales. As of September 30, 2011 and December 31, 2010, we did not have any material natural gas imbalances.

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

Accounts Receivable. We assess the collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At September 30, 2011 and December 31, 2010, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts Receivable" balance on the accompanying condensed consolidated balance sheets.

At September 30, 2011 our "Accounts Receivable" balance included $40.7 million for oil and gas sales, $4.1 million for joint interest owners and $0.3 million for other receivables. At December 31, 2010 our "Accounts Receivable" balance included $43.3 million for oil and gas sales, $2.3 million for joint interest owners and $1.4 million for other receivables.

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

The 7-1/8% senior notes due 2017 mature on June 1, 2017, and the balance of their issuance costs at September 30, 2011, was $2.7 million, net of accumulated amortization of $1.4 million. The 8-7/8% senior notes due 2020 mature on January 15, 2020, and the balance of their issuance costs at September 30, 2011, was $4.4 million, net of accumulated amortization of $0.6 million. The issuance costs associated with our revolving credit facility, which was revised and extended in May 2011, had been capitalized and is being amortized over the life of the facility. The balance of revolving credit facility issuance costs at September 30, 2011, was $3.7 million, net of accumulated amortization of $3.8 million.

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

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

We have a price-risk management policy to use derivative instruments to protect against declines in oil and natural gas prices, mainly through the purchase of price floors and collars. During the three months ended September 30, 2011 and 2010, we recognized a net gain of $0.3 million and a net loss of $0.2 million, respectively, relating to our derivative activities. During the first nine months of 2011 and 2010, we recognized a net loss of $0.8 million and a net gain of $0.8 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying condensed consolidated statements of operations. Had these losses been recognized in the oil and gas sales account they would not have materially changed our per unit sales prices received. At September 30, 2011, the Company had no derivative gains or losses in "Accumulated other comprehensive loss, net of income tax" on the accompanying condensed consolidated balance sheet. The ineffectiveness reported in "Price-risk management and other, net" for the nine months ended September 30, 2011 and 2010 was not material.

At September 30, 2011, we did not have any outstanding derivative instruments in place for future production.

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

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees, to the extent they do not exceed actual costs incurred, are recorded as a reduction to "General and administrative, net." Our supervision fees are based on COPAS guidelines. The amount of supervision fees charged for the first nine months of 2011 and 2010 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate was $10.0 million and $9.2 million in the first nine months of 2011 and 2010, respectively.

Inventories. Inventories consist primarily of tubulars and other equipment that we expect to place in service in production operations. Inventories carried at cost (weighted average method) are included in "Other current assets" on the accompanying condensed consolidated balance sheets totaling $6.3 million at September 30, 2011 and $12.8 million at December 31, 2010.

In the first nine months of 2011, we recorded a charge of $1.6 million related to inventory obsolescence in “Price-risk management and other, net” on the accompanying condensed statement of operations.

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

We follow the recognition and disclosure provisions under guidance contained in FASB ASC 740-10-25. Under this guidance, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. At September 30, 2011 our balance of unrecognized tax benefits is $1.0 million. If recognized, these tax benefits would fully impact our effective tax rate.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of September 30, 2011, we did not have any amount accrued for interest and penalties on uncertain tax positions.

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

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

| (in thousands) | September 30, 2011 | December 31, 2010 |
|---|---|---|
| Trade accounts payable (1) | $ 39,923 | $ 22,459 |
| New Zealand deferred revenue | --- | 10,000 |
| Accrued expenses | 24,559 | 21,801 |
| Asset retirement obligation – current portion | 12,274 | 8,708 |
| Accrued taxes | 7,173 | 11,156 |
| Deposit for property disposition | 5,350 | --- |
| Other payables | 1,472 | 1,470 |
| Total accounts payable and accrued liabilities | $ 90,751 | $ 75,594 |

(1) Included in "trade accounts payable" are liabilities of approximately $21.0 million and $8.1 million at September 30, 2011 and December 31, 2010, respectively, for outstanding checks. This represents the amounts by which checks were issued, but not presented by vendors to the Company's banks for collection, exceeded balances in the applicable disbursement bank accounts.

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

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

Accumulated Other Comprehensive Loss, Net of Income Tax. We follow the guidance contained in FASB ASC 220-10, which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At September 30, 2011, the Company had no gains or losses in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying condensed consolidated balance sheet. The components of accumulated other comprehensive loss and related tax effects for 2011 were as follows (in thousands):

| | Gross Value | Tax Effect | Net of Tax Value |
|---|---|---|---|
| Other comprehensive loss at December 31, 2010 | $ (218 ) | $ 81 | $ (138 ) |
| Change in fair value of cash flow hedges | (405 ) | 148 | (257 ) |
| Effect of cash flow hedges settled during the period | 623 | (229 ) | 394 |
| Other comprehensive income at September 30, 2011 | $ --- | $ --- | $ --- |

Total comprehensive income was $16.8 million and $9.3 million for the three months ended September 30, 2011 and 2010, respectively. Total comprehensive income was $78.3 million and $36.2 million for the nine months ended September 30, 2011 and 2010, respectively.

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

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

| (in thousands) | 2011 | 2010 |
|---|---|---|
| Asset Retirement Obligation recorded as of January 1 | $ 78,879 | $ 64,236 |
| Accretion expense | 3,482 | 2,927 |
| Liabilities incurred for new wells and facilities construction | 490 | 1,018 |
| Reductions due to sold and abandoned wells | (335 ) | (463 ) |
| Revisions in estimated cash flows | 20,995 | --- |
| Asset Retirement Obligation as of September 30 | $ 103,511 | $ 67,718 |

In the third quarter of 2011, we performed our annual revaluation of the asset retirement obligation, increasing the liability as a result of an increase in the expected abandonment costs for some of our wells and facilities and a decrease in the expected timing of abandonment activities for wells and facilities in certain fields. This revaluation increase is shown above as “Revisions in estimated cash flows.”

At September 30, 2011 and December 31, 2010, approximately $12.3 million and $8.7 million, respectively, of our asset retirement obligation are classified as a current liability in “Accounts payable and accrued liabilities” on the accompanying condensed consolidated balance sheets.

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

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

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

(3) Share-Based Compensation

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

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

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

Net cash proceeds from the exercise of stock options were $1.1 million and $0.9 million for the nine months ended September 30, 2011 and 2010, respectively. The actual income tax benefit from stock option exercises was $1.1 million and $0.2 million for the nine months ended September 30, 2011 and 2010, respectively.

Share-based compensation expense for both stock options and restricted stock issued to both employees and non-employees, which was recorded in "General and administrative, net" in the accompanying condensed consolidated statements of operations, was $3.2 million and $2.4 million for the three months ended September 30, 2011 and 2010, respectively, and was $8.8 million and $6.9 million for the nine month periods ended September 30, 2011 and 2010. Share-based compensation recorded in lease operating cost was $0.1 million for the three months ended September 30, 2011 and 2010, and was $0.2 million and $0.3 million for the nine month periods ended September 30, 2011 and 2010, respectively. We also capitalized $1.1 million and $0.4 million of share-based compensation for the three months ended September 30, 2011 and 2010, respectively, and capitalized $3.1 million and $1.2 million for the nine month periods ended September 30, 2011 and 2010. We view all awards of share-based compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the service period of the award.

Stock Options

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

| | Three Months Ended September 30, | | Nine months Ended September 30, | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Dividend yield | N/A | N/A | 0 % | 0 % |
| Expected volatility | N/A | N/A | 58.8 % | 63.0 % |
| Risk-free interest rate | N/A | N/A | 1.9 % | 2.1 % |
| Expected life of options (in years) | N/A | N/A | 3.8 | 4.3 |
| Weighted-average grant-date fair value | N/A | N/A | $ 19.17 | $ 12.60 |

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

At September 30, 2011, we had $3.6 million of unrecognized compensation cost related to stock options, which is expected to be recognized over a weighted-average period of 0.9 years. The following table represents stock option activity for the nine months ended September 30, 2011:

| | Shares | Wtd. Avg. Exercise Price |
|---|---|---|
| Options outstanding, beginning of period | 1,361,779 | $ 29.67 |
| Options granted | 307,394 | $ 42.56 |
| Options canceled | (67,529 ) | $ 55.19 |
| Options exercised | (223,963 ) | $ 22.64 |
| Options outstanding, end of period | 1,377,681 | $ 32.44 |
| Options exercisable, end of period | 731,300 | $ 30.96 |

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at September 30, 2011 was $3.2 million and 6.0 years and $2.3 million and 4.4 years, respectively. The total intrinsic value of options exercised during the nine months ended September 30, 2011 was $4.2 million.

Restricted Stock

The plans, as described in Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010, allow for the issuance of restricted stock awards that may not be sold or otherwise transferred until certain restrictions have lapsed. The unrecognized compensation cost related to these awards is expected to be expensed over the period the restrictions lapse (generally one to three years).

The compensation expense for these awards was determined based on the closing market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of September 30, 2011, we had unrecognized compensation expense of $18.9 million related to restricted stock awards which is expected to be recognized over a weighted-average period of 1.2 years.  The grant date fair value of shares vested during the nine months ended September 30, 2011 was $8.3 million.

The following table represents restricted stock activity for the nine months ended September 30, 2011:

| | Shares | Wtd. Avg. Grant Price |
|---|---|---|
| Restricted shares outstanding, beginning of period | 734,286 | $ 22.87 |
| Restricted shares granted | 490,050 | $ 40.50 |
| Restricted shares canceled | (30,542 ) | $ 31.53 |
| Restricted shares vested | (337,556) | $ 24.68 |
| Restricted shares outstanding, end of period | 856,238 | $ 31.93 |

(4) Earnings Per Share

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

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

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

| | Three Months Ended September 30, 2011 | | | Three Months Ended September 30, 2010 | | |
|---|---|---|---|---|---|---|
| | Income from Continuing Operations | Shares | Per Share Amount | Income from Continuing Operations | Shares | Per Share Amount |
| Basic EPS: | | | | | | |
| Income from continuing operations, and Share Amounts | $17,007 | 42,470 | | $9,403 | 37,880 | |
| Less: Income from continuing operations allocated to unvested shares | (326) | --- | | (179) | --- | |
| Income from continuing operations allocated to common shares | $16,681 | 42,470 | $0.39 | $9,224 | 37,880 | $0.24 |
| Dilutive Securities: | | | | | | |
| Plus: Income from continuing operations allocated to unvested shares | 326 | --- | | 179 | --- | |
| Less: Income from continuing operations re-allocated to unvested shares | (324) | --- | | (178) | --- | |
| Stock Options | --- | 208 | | --- | 178 | |
| Diluted EPS: | | | | | | |
| Income from continuing operations allocated to common shares, and assumed share conversions | $16,683 | 42,678 | $0.39 | $9,225 | 38,058 | $0.24 |

| | Nine months Ended September 30, 2011 | | | Nine months Ended September 30, 2010 | | |
|---|---|---|---|---|---|---|
| | Income from Continuing Operations | Shares | Per Share Amount | Income from Continuing Operations | Shares | Per Share Amount |
| Basic EPS: | | | | | | |
| Income from continuing operations, and Share Amounts | $63,938 | 42,365 | | $36,156 | 37,792 | |
| Less: Income from continuing operations allocated to unvested shares | (1,195) | --- | | (693) | --- | |
| Income from continuing operations allocated to common shares | $62,743 | 42,365 | $1.48 | $35,463 | 37,792 | $0.94 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Dilutive Securities: | | | | | | |
| Plus: Income from continuing operations allocated to unvested shares | 1,195 | --- | | 693 | --- | |
| Less: Income from continuing operations re-allocated to unvested shares | (1,188 ) | --- | | (689 ) | --- | |
| Stock Options | --- | 254 | | --- | 203 | |
| Diluted EPS: | | | | | | |
| Income from continuing operations allocated to common shares, and assumed share conversions | $62,750 | 42,619 | $1.47 | $35,467 | 37,995 | $0.93 |

Options to purchase approximately 1.4 million shares at an average exercise price of $32.44 were outstanding at September 30, 2011, while options to purchase approximately 1.4 million shares at an average exercise price of $29.00 were outstanding at September 30, 2010. Approximately 0.8 million and 0.7 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months ended September 30, 2011 and 2010, respectively, and 0.7 million and 0.8 million stock options to purchase shares were not included in the computation of Diluted EPS for the nine months ended September 30, 2011 and 2010 because these stock options were antidilutive, in that the sum of the stock option price, unrecognized compensation expense and excess tax benefits recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during those periods.

(5) Long-Term Debt

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

| | September 30, 2011 | December 31, 2010 |
|---|---|---|
| Bank Borrowings | $ --- | $ --- |
| 7-1/8% senior notes due 2017 | 250,000 | 250,000 |
| 8-7/8% senior notes due 2020 | 221,809 | 221,624 |
| Long-Term Debt | $ 471,809 | $ 471,624 |

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

We have capitalized interest on our unproved properties in the amount of $2.0 million and $1.9 million for the three months ended September 30, 2011 and 2010, respectively and we have capitalized interest on our unproved properties in the amount of $5.7 million and $5.5 million for the nine months ended September 30, 2011 and 2010, respectively.

Bank Borrowings. In May 2011 we renewed and extended our $500.0 million credit facility with a syndicate of ten banks through May 12, 2016, and have included a feature that allows the Company to increase the aggregate facility amount available up to $700.0 million with additional commitments from the lenders and subject to the terms of the credit agreement. We also increased our borrowing base to $400.0 million from $300.0 million, while the commitment amount remains at $300.0 million. Debt issuance costs of approximately $0.7 million related to this extension of the credit facility were capitalized and are being amortized over the life of the facility.

At September 30, 2011 and December 31, 2010 we had no borrowings under our credit facility. The interest rate on our credit facility is either (a) the lead bank’s prime plus an applicable margin or (b) Eurodollar rate plus an applicable margin. However with respect to (a), if the lead bank’s prime rate is not higher than each of the federal funds rate plus ½%, and the adjusted London Interbank Offered Rate (“LIBOR”) plus 1%, the greatest of these three rates will then apply. The applicable margins vary depending on the level of outstanding debt with escalating rates of 50 to 150 basis points above the Alternative Base Rate and escalating rates of 150 to 250 basis points for Eurodollar rate loans. The commitment fee associated with the unfunded portion of the borrowing base is set at 50 basis points. At September 30, 2011, the lead bank’s prime rate was 3.25%.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $15.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $50.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX) and limitations on incurring other debt. Since inception, no cash dividends have been declared on our common stock. We are currently in compliance with the provisions of this agreement. The credit facility is secured by our domestic oil and natural gas properties. Under the terms of the credit facility, we can increase the commitment amount to the total amount of the borrowing base with unanimous consent of the bank group as it might change from time to time. In November 2011, in conjunction with our regularly scheduled borrowing base redetermination which occurs every six months, our borrowing base was reaffirmed at the current level and our commitment amount remains the same.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $0.6 million and $0.5 million for the three months ended September 30, 2011 and 2010, respectively, and $1.8 million and $1.3 million for the nine months ended September 30, 2011 and 2010, respectively. The amount of commitment fees included in interest expense, net was $0.4 million for the three month periods ended September 30, 2011 and 2010, respectively, and $1.1 million and $1.0 million for the nine months ended September 30, 2011 and 2010, respectively.

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

Interest expense on the 8-7/8% senior notes due 2020, including amortization of debt issuance costs and debt discount, totaled $5.1 million for each of the three months ended September 30, 2011 and 2010, respectively, and $15.4 million for the nine months ended September 30, 2011 and 2010, respectively.

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

Interest expense on the 7-1/8% senior notes due 2017, including amortization of debt issuance costs, totaled $4.5 million for the three months ended September 30, 2011 and 2010, respectively, and 13.6 million for the nine months ended September 30, 2011 and 2010, respectively.

(6) Discontinued Operations

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

Our income from discontinued operations was $14.2 million for the nine months ended September 30, 2011, which equated to $0.33 per basic and diluted share for the period. Our loss from discontinued operations, net of taxes was $0.2 million for the nine months ended September 30, 2010, which equated to $0.00 per basic and diluted share for the period. Our cash provided by operating activities – discontinued operations was less than $0.1 million for the nine months ended September 30, 2011 and 2010.

(7) Acquisitions and Dispositions

In October 2011, we closed the sale of certain properties located in Louisiana, Texas and Alabama. The fields in Louisiana include Horseshoe Bayou/Bayou Sale, High Island, Bayou Penchant, Jeanerette and Cote Blanche Island. The Texas fields include Bego South and Briscoe Ranch. The Alabama field is Chunchula. As a result, the Company received sale proceeds of $48.8 million, net of $4.7 million in purchase price adjustments related to these properties. This sale also included the buyer's assumption of $27.7 million for asset retirement obligations on these properties.

(8) Fair Value Measurements

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

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair value of the bank borrowings approximate the carrying amounts as of September 30, 2011 and December 31, 2010, and was determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of September 30, 2011 and December 31, 2010, the fair value of our senior notes due 2017, was $245.0 million, or 98% of face value, and $254.7 million, or 101.9% of face value, respectively. Based upon quoted market prices as of September 30, 2011 and December 31, 2010, the fair value of our senior notes due 2020, which were issued in November 2009, were $237.4 million, or 106% of face value and $242.3 million, or 107.7% of face value, respectively. The carrying value of our senior notes due 2017 was $250.0 million at September 30, 2011 and December 31, 2010, while the carrying value of our senior notes due 2020 was $221.8 million and $221.6 million at September 30, 2011 and December 31, 2010, respectively.

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

| | Fair Value Measurements at September 30, 2011 | | | |
|---|---|---|---|---|
| Assets | Total | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) |

| | | | | |
|---|---|---|---|---|
| Money Market Funds | $ 0.1 | $ 0.1 | $ --- | $ --- |
| Natural Gas Derivatives | $ --- | $ --- | $ --- | $ --- |
| Oil Derivatives | $ --- | $ --- | $ --- | $ --- |

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

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

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

(9) Condensed Consolidating Financial Information

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

Condensed Consolidating Balance Sheets

| (in thousands) | September 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Swift Energy Company (Issuer) | Swift Energy Operating, LLC (Guarantor) | Other Subsidiaries | Eliminations | Swift Energy Company Consolidated |
| ASSETS | | | | | |
| Current assets | $--- | $76,609 | $28 | $--- | $ 76,637 |
| Property and equipment | --- | 1,835,609 | --- | --- | 1,835,609 |
| Investment in subsidiaries (equity method) | 971,493 | --- | 886,009 | (1,857,502) | --- |
| Other assets | --- | 12,222 | 85,455 | (85,455) | 12,222 |
| Total assets | $971,493 | $1,924,440 | $971,492 | $(1,942,957) | $ 1,924,468 |
| | | | | | |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | | | | |
| Current liabilities | $--- | $187,578 | $(1) | $--- | $ 187,577 |
| Long-term liabilities | --- | 850,853 | --- | (85,455) | 765,398 |
| Stockholders' equity | 971,493 | 886,009 | 971,493 | (1,857,502) | 971,493 |
| Total liabilities and stockholders' equity | $971,493 | $1,924,440 | $971,492 | $(1,942,957) | $ 1,924,468 |

| (in thousands) | December 31, 2010 | | | | |
|---|---|---|---|---|---|
| | Swift Energy Company (Issuer) | Swift Energy Operating, LLC (Guarantor) | Other Subsidiaries | Eliminations | Swift Energy Company Consolidated |
| ASSETS | | | | | |
| Current assets | $--- | $158,335 | $23 | $--- | $ 158,358 |
| Property and equipment | --- | 1,572,845 | --- | --- | 1,572,845 |
| Investment in subsidiaries (equity method) | 880,017 | --- | 808,780 | (1,688,797) | --- |
| Other assets | --- | 12,713 | 81,221 | (81,221) | 12,713 |
| Total assets | $880,017 | $1,743,893 | $890,024 | $(1,770,018) | $ 1,743,916 |
| | | | | | |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Current liabilities | $--- | $146,728 | $10,007 | $--- | $ 156,735 |
| Long-term liabilities | --- | 788,385 | --- | (81,221 ) | 707,164 |
| Stockholders’ equity | 880,017 | 808,780 | 880,017 | (1,688,797 ) | 880,017 |
| Total liabilities and stockholders’ equity | $880,017 | $1,743,893 | $890,024 | $(1,770,018 ) | $ 1,743,916 |

Condensed Consolidating Statements of Income

| (in thousands) | Three Months Ended September 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Swift Energy Company (Issuer) | Swift Energy Operating, LLC (Guarantor) | Other Subsidiaries | Eliminations | Swift Energy Company Consolidated |
| Revenues | $--- | $142,532 | $--- | $--- | $142,532 |
| Expenses | --- | 115,137 | --- | --- | 115,137 |
| Income before the following: | --- | 27,395 | --- | --- | 27,395 |
| Equity in net earnings of subsidiaries | 16,976 | --- | 17,007 | (33,983) | --- |
| Income from continuing operations, before income taxes | 16,976 | 27,395 | 17,007 | (33,983) | 27,395 |
| Income tax provision | --- | 10,388 | --- | --- | 10,388 |
| Income from continuing operations | 16,976 | 17,007 | 17,007 | (33,983) | 17,007 |
| Income from discontinued operations, net of taxes | --- | --- | (31) | --- | (31) |
| Net income | $16,976 | $17,007 | $16,976 | $(33,983) | $16,976 |

| (in thousands) | Nine months Ended September 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Swift Energy Company (Issuer) | Swift Energy Operating, LLC (Guarantor) | Other Subsidiaries | Eliminations | Swift Energy Company Consolidated |
| Revenues | $--- | $444,038 | $--- | $--- | $444,038 |
| Expenses | --- | 342,278 | --- | --- | 342,278 |
| Income before the following: | --- | 101,760 | --- | --- | 101,760 |
| Equity in net earnings of subsidiaries | 78,185 | --- | 63,938 | (142,123) | --- |
| Income from continuing operations, before income taxes | 78,185 | 101,760 | 63,938 | (142,123) | 101,760 |
| Income tax provision | --- | 37,822 | --- | --- | 37,822 |
| Income from continuing operations | 78,185 | 63,938 | 63,938 | (142,123) | 63,938 |
| Income from discontinued operations, net of taxes | --- | --- | 14,247 | --- | 14,247 |

| | | | | | |
|---|---|---|---|---|---|
| Net income | $78,185 | $63,938 | $78,185 | $ (142,123 ) | $ 78,185 |

| (in thousands) | Three Months Ended September 30, 2010 | | | | |
|---|---|---|---|---|---|
| | Swift Energy Company (Issuer) | Swift Energy Operating, LLC (Guarantor) | Other Subsidiaries | Eliminations | Swift Energy Company Consolidated |
| Revenues | $--- | $105,646 | $--- | $ --- | $ 105,646 |
| Expenses | --- | 90,591 | --- | --- | 90,591 |
| | | | | | |
| Income before the following: | --- | 15,055 | --- | --- | 15,055 |
| Equity in net earnings of subsidiaries | 9,330 | --- | 9,403 | (18,733) | --- |
| | | | | | |
| Income from continuing operations, before income taxes | 9,330 | 15,055 | 9,403 | (18,733) | 15,055 |
| Income tax provision | --- | 5,652 | --- | --- | 5,652 |
| | | | | | |
| Income from continuing operations | 9,330 | 9,403 | 9,403 | (18,733) | 9,403 |
| Loss from discontinued operations, net of taxes | --- | --- | (73) | --- | (73) |
| | | | | | |
| Net income | $9,330 | $9,403 | $9,330 | $ (18,733) | $ 9,330 |

| (in thousands) | Nine months Ended September 30, 2010 | | | | |
|---|---|---|---|---|---|
| | Swift Energy Company (Issuer) | Swift Energy Operating, LLC (Guarantor) | Other Subsidiaries | Eliminations | Swift Energy Company Consolidated |
| Revenues | $--- | $322,392 | $--- | $ --- | $ 322,392 |
| Expenses | --- | 265,448 | --- | --- | 265,448 |
| | | | | | |
| Income before the following: | --- | 56,944 | --- | --- | 56,944 |
| Equity in net earnings of subsidiaries | 35,994 | --- | 36,156 | (72,150) | --- |
| | | | | | |
| Income from continuing operations, before income taxes | 35,994 | 56,944 | 36,156 | (72,150) | 56,944 |
| Income tax provision | --- | 20,788 | --- | --- | 20,788 |
| | | | | | |
| Income from continuing operations | 35,994 | 36,156 | 36,156 | (72,150) | 36,156 |
| Loss from discontinued operations, net of taxes | --- | --- | (162) | --- | (162) |

| | | | | | |
|---|---|---|---|---|---|
| Net income | $35,994 | $36,156 | $35,994 | $(72,150) | $35,994 |

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Condensed Consolidating Statements of Cash Flows

| (in thousands) | Nine months Ended September 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Swift Energy Company (Issuer) | Swift Energy Operating, LLC (Guarantor) | Other Subsidiaries | Eliminations | Swift Energy Company Consolidated |
| Cash flow from operations | $--- | $288,514 | $5 | $ --- | $ 288,519 |
| Cash flow from investing activities | --- | (357,670) | 5,000 | (5,000) | (357,670) |
| Cash flow from financing activities | --- | (1,217) | (5,000) | 5,000 | (1,217) |
| Net increase (decrease) in cash | --- | (70,373) | 5 | --- | (70,368) |
| Cash, beginning of period | --- | 86,346 | 21 | --- | 86,367 |
| Cash, end of period | $--- | $15,973 | $26 | $ --- | $ 15,999 |

| (in thousands) | Nine months Ended September 30, 2010 | | | | |
|---|---|---|---|---|---|
| | Swift Energy Company (Issuer) | Swift Energy Operating, LLC (Guarantor) | Other Subsidiaries | Eliminations | Swift Energy Company Consolidated |
| Cash flow from operations | $--- | $193,741 | $(29) | $ --- | $ 193,712 |
| Cash flow from investing activities | --- | (223,246) | 5,000 | (5,000) | (223,246) |
| Cash flow from financing activities | --- | (3,427) | (5,000) | 5,000 | (3,427) |
| Net decrease in cash | --- | (32,932) | (29) | --- | (32,961) |
| Cash, beginning of period | --- | 38,405 | 64 | --- | 38,469 |
| Cash, end of period | $--- | $5,473 | $35 | $ --- | $ 5,508 |

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

You should read the following discussion and analysis in conjunction with our financial information and our consolidated financial statements and accompanying notes included in this report and our annual reports on Form 10-K for the years ended December 31, 2010, 2009, and 2008. Unless otherwise noted, both historical information for all periods and forward-looking information provided in this Management's Discussion and Analysis relates solely to our continuing operations located in the United States, and excludes our New Zealand discontinued operations. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 32 of this report.

Overview

We are an independent oil and natural gas company formed in 1979, and we are engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from our Texas properties as well as onshore and inland waters of Louisiana. We are one of the largest producers of crude oil in the state of Louisiana, and hold a large acreage position in Texas prospective for liquids-rich Eagle Ford shale and Olmos tight sands development. Oil production accounted for 37% of our third quarter of 2011 production and 69% of our oil and gas revenues, and combined production for both oil and natural gas liquids ("NGLs") made up 47% of our third quarter of 2011 production and 79% of our oil and gas sales. This emphasis has allowed us to benefit from better margins for oil production than natural gas production during the quarter.

Third Quarter 2011 Highlights

Increases in Earnings and Production. Our income increased by $7.6 million and our production volumes increased by 23% in the third quarter of 2011 when compared to the same period in 2010. Natural gas production volumes increased 67% in the third quarter of 2011, due to our recent South Texas activities, while oil volumes decreased 7% and NGL volumes decreased 4% from third quarter of 2010 levels, respectively. Sequentially, production decreased 4% from production levels in the second quarter of 2011. Prices received for oil and NGLs in the third quarter of 2011 were 38% and 45% higher, respectively, while natural gas prices were 5% lower than average prices we received in the third quarter of 2010.

Negative Impacts on Production Quantities in the Third Quarter of 2011. Our third quarter 2011 production was negatively impacted due to several factors:

- Tropical Storm Lee caused us to shut-in production for properties along the Louisiana coast for several days.
- Delays in the commissioning of dedicated transportation and processing through a newly constructed third-party pipeline handing natural gas production in our South Texas Area. This pipeline and processing was fully operational as of the beginning of October and should not affect fourth quarter production. This new pipeline services our AWP Eagle Ford and Olmos production and was built by a midstream provider. We have a long-term processing and transportation agreement for this pipeline under which firm capacity is now available to us for up to 90 million cubic feet of gas per day.
- Periodic transportation and processing curtailments under our previously existing interruptible natural gas agreements in our South Texas AWP area prior to the new pipeline being commissioned.
- The failure in late September of a third-party operated gathering line handing natural gas production from our Fasken Eagle Ford field.

Liquidity at Quarter-End. We ended the third quarter of 2011 with $16.0 million of cash and cash equivalents on our balance sheet. Taken together with our available borrowing capacity under our credit agreement at September 30, 2011, our liquidity provides capital, for our 2011 drilling program.

Third Quarter 2011 Drilling and Operational Activities. In our South Texas core region, ten horizontal development wells were drilled to the Eagle Ford shale formation, and two Olmos horizontal wells and two Eagle Ford horizontal wells were drilling at quarter-end. We performed completion operations on four Olmos horizontal wells and six Eagle Ford horizontal wells during the third quarter. At the end of 2010, our South Texas core region surpassed Southeast Louisiana in terms of both production and proven reserves. We had also entered into a long-term agreement with a major industry service provider for South Texas, securing access to hydraulic fracturing services at competitive prices for a two-year period with less than one year still remaining on the contract.

In our Southeast Louisiana core region, recompletion and production optimization work continued during the quarter at the Lake Washington field, including 6 recompletions, 1 gas lift modification, 1 well returned to production, and 8 sliding sleeves. The average initial production response from all of these operations combined, which was approximately 5,000 Boe per day, helped to manage natural production declines in the Lake Washington field. As a result of these low-cost operations, and the impact of two new wells coming on-line during the second quarter, third quarter Lake Washington field production was flat compared to the second quarter 2011 levels. We will continue to focus on relatively low risk, low cost oil activity in this area and also plan to re-commence drilling in the Lake Washington field in the fourth quarter of 2011 and during 2012.

In our Central Louisiana/East Texas core region, we drilled one operated well and participated in one non-operated well in our Burr Ferry field during the third quarter of 2011. One additional well, which was spud in our Masters Creek area in September, is expected to be completed during the fourth quarter of 2011.

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

During the third quarter of 2011 in our Burr Ferry field, we and our partner expanded our original joint operating area. We have also entered into another agreement to jointly develop acreage in a newly identified second operating area adjacent to the first operating area. There are now approximately 80,000 gross acres leased in the first joint operating area in which we hold a 50% working interest. We also own approximately 39,000 fee mineral acres in the area. In the second joint operating area, there are now approximately 91,000 gross acres leased in which we hold a 45% working interest. Our position in both areas is non-operated and additional leasing is expected to continue in both areas.

Dispositions. In October 2011, we sold our interests in six fields in South Louisiana, two in Texas and one in Alabama for $48.8 million, net of $4.7 million in purchase price adjustments and the buyer's assumption of approximately $27.7 million of asset retirement related to these properties. The sales price is subject to customary post-closing adjustments which are not expected to be material. The fields in Louisiana include Horseshoe Bayou/Bayou Sale, High Island, Bayou Penchant, Jeanerette and Cote Blanche Island. The Texas fields include Bego South and Briscoe Ranch. The Alabama field includes Chunchula.

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

2011 Objectives

In 2011, we have been focused on accelerating our pace of development in South Texas, improving our results through more efficient execution and exploiting other areas of our asset base. Our exposure to liquids rich production growth in South Texas, our oil production in South Louisiana, our growing leasehold acreage in the Austin Chalk and our deep exploration prospect inventory along the Gulf Coast together provide a uniquely positioned resource portfolio. For 2011, we are targeting reserves growth of 15% to 20% over 2010 levels, and due to events beyond our control which negatively affected third quarter 2011 production (as detailed above), an increase in production volumes of 24% to 26% over 2010 levels.

Results of Operations

Summary Prior Quarter Comparison

In the third quarter of 2011 we had revenues of $142.5 million, a decrease of 9% compared to second quarter 2011 levels. Our weighted average sales price received decreased 7% to $56.31 per Boe from $60.29 per Boe, while our production volumes were down 4%. This $14.9 million decrease in revenues from second quarter 2011 levels was mainly due to a decrease in oil production and prices.

Our overall costs and expenses decreased in the third quarter of 2011 by $0.4 million when compared to second quarter 2011 levels but were higher on a Boe basis, as production volumes decreased 4%. Depreciation, depletion and amortization expense decreased 3%, mainly due to lower production offset by a higher depletable base. Lease operating costs decreased by 2% due to decreased repairs and maintenance and other costs in our South Texas core region. Severance and other taxes increased 9% as the second quarter included retroactive severance tax refunds for several properties.

Net income from continuing operations for the third quarter of 2011 was $17.0 million compared to $26.7 million in the second quarter of 2011.

Core Regions

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

- South Texas
  - Olmos

AWP
Sun TSH
Las Tiendas

  - Eagle Ford

Hawkville AWP
Hawkville Artesia Wells
Hawkville Fasken

- Southeast Louisiana

Lake Washington
Bay de Chene

- Central and South Louisiana / East Texas

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

* These properties were sold in the fourth quarter, effective October 21, 2011.

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

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

| Core Regions | Oil and Gas Sales (In Millions) | | Net Oil and Gas Production Volumes (MBoe) | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |

| | | | | |
|---|---|---|---|---|
| S. E. Louisiana | $ 70.8 | $ 60.2 | 783 | 934 |
| South Texas | 52.1 | 29.0 | 1,449 | 796 |
| Central and South Louisiana / E. Texas | 19.3 | 16.1 | 292 | 328 |
| Other | 0.9 | 0.5 | 18 | 14 |
| Total | $ 143.1 | $ 105.8 | 2,542 | 2,072 |

2011 Third Quarter Revenues Breakdown. Oil and gas sales for the third quarter of 2011 increased by 35%, or $37.3 million, from the level of those revenues for the comparable 2010 period, and our net production volumes in the third quarter of 2011 increased by 23%, or 0.5 MMBoe, from net production volumes in the third quarter of 2010. Average prices for oil increased to $105.55 per Bbl in the third quarter of 2011 from $76.39 per Bbl in the third quarter of 2010. Average natural gas prices decreased to $3.68 per Mcf in the third quarter of 2011 from $3.87 per Mcf in the third quarter of 2010. Average NGL prices increased to $57.76 per Bbl in the third quarter of 2011 from $39.88 per Bbl in the third quarter of 2010. In the third quarter of 2011, total sales and production from properties sold were $7.9 million and 154.4 MBoe, respectively.

In the third quarter of 2011, our $37.3 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $30.2 million favorable impact on sales, of which $27.3 million was attributable to the 38% increase in average oil prices received and $4.4 million was attributable to the 45% increase in NGL prices, offset by a decrease of $1.5 million attributable to the 5% decrease in natural gas prices; and
- Volume variances that had a $7.1 million favorable impact on sales, offset by a $5.2 million decrease attributable to the less than 0.1 million Bbl decrease in oil production volumes, a $0.4 million decrease due to the less than 0.1 million Bbl decrease in NGL production volumes, and a $12.7 million increase due to the 3.3 Bcf increase in natural gas production volumes.

The following table provides additional information regarding our quarterly oil and gas sales, excluding any effects of our hedging activities, for the three months ended September 30, 2011 and 2010:

| | Production Volume | | | | Average Price | | |
|---|---|---|---|---|---|---|---|
| | Oil (MBbl) | NGL (MBbl) | Gas (Bcf) | Combined (MBoe) | Oil (Bbl) | NGL (Bbl) | Natural Gas (Mcf) |
| Three Months Ended September 30, 2011 | 937 | 247 | 8.1 | 2,542 | $ 105.55 | $ 57.76 | $ 3.68 |
| Three Months Ended September 30, 2010 | 1,005 | 256 | 4.9 | 2,072 | $ 76.39 | $ 39.88 | $ 3.87 |

During the third quarter of 2011, we recorded a net gain of $0.3 million related to our derivative activities, while during the third quarter of 2010 we recorded a net loss of $0.2 million from these activities. This activity is recorded in “Price-risk management and other, net” on the accompanying condensed statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been $105.55 and $76.44 for the third quarters of 2011 and 2010, respectively, and our average natural gas price would have been $3.71 and $3.81 for the third quarters of 2011 and 2010, respectively.

Expenses. Our expenses in the third quarter of 2011 increased $24.5 million, or 27%, compared to the third quarter of 2010 for the reasons noted below.

Lease Operating Expenses (“LOE”). These expenses increased $5.2 million, or 25%, compared to the level of such expenses in the third quarter of 2010. Lease operating costs increased during 2011 due to higher product transportation costs, higher salt water disposal costs, as well as other various cost increases from our South Texas core region. Our lease operating costs per Boe produced were $10.31 and $10.12 for the third quarters of 2011 and 2010, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses increased $13.6 million, or 33% from the third quarter of 2010. The increase was due to a higher depletable base and higher production volumes, partially offset by higher reserves volumes. Our DD&A rate per Boe of production was $21.40 and $19.69 in the third quarters of 2011 and 2010, respectively, resulting from increases in the per unit cost of reserves additions in 2011.

General and Administrative Expenses, Net. These expenses increased $2.7 million, or 30%, from the level of such expenses in the third quarter of 2010. The increase was primarily due to higher stock and deferred compensation amounts and higher salaries and burdens in the third quarter of 2011, partially offset by higher capitalized amounts. For the third quarters of 2011 and 2010, our capitalized general and administrative costs totaled $7.5 million and $5.9 million, respectively. Our net general and administrative expenses per Boe produced increased to $4.48 per Boe in the third quarter of 2011 from $4.21 per Boe in the third quarter of 2010. The portion of supervision fees recorded as a reduction to general and administrative expenses were $3.4 million and $3.2 million for the third quarters of 2011 and 2010, respectively.

Severance and Other Taxes. These expenses increased $2.7 million, or 25%, from the third quarter of 2010 along with a production increase of 23%. Severance and other taxes, as a percentage of oil and gas sales, were approximately 9.5% and 10.2% in the third quarters of 2011 and 2010, respectively. The percentage decrease was due primarily to a shift in product and regional mix as well as reduced tax rates for tight sand gas production related to South Texas Olmos and Eagle Ford completions.

Interest. Our gross interest cost in the third quarter of 2011 was $10.4 million, of which $2.0 million was capitalized. Our gross interest cost in the third quarter of 2010 was $10.1 million, of which $1.9 million was capitalized.

Income Taxes. Our effective income tax rate was 37.9% and 37.5% for the third quarters of 2011 and 2010, respectively. Our U.S. federal income tax returns for 2002 forward, our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2004, and our Texas franchise tax returns after 2006 remain subject to examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

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

Net Income. Our third quarter 2011 net income of $17.0 million increased in comparison to our third quarter 2010 net income of $9.3 million.

Revenues and Expenses — Nine Months Ended September 30, 2011 and 2010

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

| Core Regions | Oil and Gas Sales (In Millions) | | Net Oil and Gas Production Volumes (MBoe) | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| S. E. Louisiana | $ 219.5 | $ 183.4 | 2,473 | 2,814 |
| South Texas | 156.3 | 86.3 | 4,181 | 2,318 |
| Central and South Louisiana / E. Texas | 68.4 | 49.3 | 1,129 | 968 |
| Other | 2.3 | 1.9 | 45 | 45 |
| Total | $ 446.5 | $ 320.9 | 7,828 | 6,145 |

2011 First Nine Months Revenues Breakdown. Oil and gas sales for the first nine months of 2011 increased by 39%, or $125.7 million, from the level of those revenues for the comparable 2010 period, and our net production volumes in the first nine months of 2011 increased by 27%, or 1.7 MMBoe, from net production volumes in the first nine months of 2010. Average prices for oil increased to $105.43 per Bbl in the first nine months of 2011 from $77.42 per Bbl in the first nine months of 2010. Average natural gas prices decreased to $3.81 per Mcf in the first nine months of 2011 from $4.11 per Mcf in the first nine months of 2010. Average NGL prices increased to $51.79 per Bbl in the first nine months of 2011 from $42.31 per Bbl in the first nine months of 2010. In the first nine months of 2011, total sales and production from properties sold were $26.3 million and 494.9 MBoe, respectively.

In the first nine months of 2011, our $125.7 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had an $83.3 million favorable impact on sales, of which $81.7 million was attributable to the 36% increase in average oil prices received and $8.8 million was attributable to the 22% increase in NGL prices, offset by a decrease of $7.2 million was attributable to the 7% decrease in natural gas prices; and
- Volume variances that had a $42.4 million favorable impact on sales, with a $1.1 million decrease attributable to the less than 0.1 million Bbl decrease in oil production volumes, a $3.9 million increase due to the 0.1 million Bbl increase in NGL production volumes, and a $39.6 million increase due to the 9.6 Bcf increase in natural gas production volumes.

The following table provides additional information regarding our oil and gas sales, excluding any effects of our hedging activities, for the nine months ended September 30, 2011 and 2010:

| | Production Volume | | | | Average Price | | |
|---|---|---|---|---|---|---|---|
| | Oil (MBbl) | NGL (MBbl) | Gas (Bcf) | Combined (MBoe) | Oil (Bbl) | NGL (Bbl) | Natural Gas (Mcf) |
| Nine months Ended September 30, 2011 | 2,915 | 930 | 23.9 | 7,828 | $ 105.43 | $ 51.79 | $ 3.81 |
| Nine months Ended September 30, 2010 | 2,929 | 839 | 14.3 | 6,145 | $ 77.42 | $ 42.31 | $ 4.11 |

During the first nine months of 2011, we recorded a net loss of $0.8 million related to our derivative activities, while during the first nine months of 2010 we recorded a net gain of $0.8 million from these activities. This activity is recorded in “Price-risk management and other, net” on the accompanying condensed statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been $105.24 and $77.53 for the first nine months of 2011 and 2010, respectively, and our average natural gas price would have been $3.80 and $4.15 for the first nine months of 2011 and 2010, respectively.

Expenses. Our expenses in the first nine months of 2011 increased $76.8 million, or 29%, compared to the first nine months of 2010 for the reasons noted below.

Lease Operating Expenses (“LOE”). These expenses increased $18.7 million, or 31%, compared to the level of such expenses in the first nine months of 2010. Lease operating costs increased during the first nine months of 2011 due to higher product transportation costs, higher salt water disposal costs, higher repair and maintenance costs, higher equipment and compressor rental costs, as well as other various cost increases from our South Texas core region. Our lease operating costs per Boe produced were $10.00 and $9.69 for the first nine months of 2011 and 2010, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses increased $45.0 million, or 38%, from the first nine months of 2010. The increase was due to a higher depletable base and higher production volumes, partially offset by higher reserves volumes. Our DD&A rate per Boe of production was $20.84 and $19.22 in the first nine months of 2011 and 2010, respectively, resulting from increases in the per unit cost of reserves additions in 2011.

General and Administrative Expenses, Net. These expenses increased $6.7 million, or 26%, from the level of such expenses in the first nine months of 2010. The increase was primarily due to higher stock and deferred compensation amounts in the first nine months of 2011, partially offset by higher capitalized amounts. For the first nine months of 2011 and 2010, our capitalized general and administrative costs totaled $21.9 million and $17.5 million, respectively. Our net general and administrative expenses per Boe produced decreased to $4.18 per Boe in the first nine months of 2011 from $4.23 per Boe in the first nine months of 2010. The portion of supervision fees recorded as a reduction to general and administrative expenses was $10.0 million and $9.2 million for the first nine months of 2011 and 2010, respectively.

Severance and Other Taxes. These expenses increased $5.2 million, or 15%, from the first nine months of 2010. The increase was due primarily to higher revenues from higher natural gas production and higher oil prices. Severance and other taxes, as a percentage of oil and gas sales, were approximately 8.8% and 10.6% for the first nine months of 2011 and 2010, respectively. The decrease in 2011 was primarily driven by a shift in product and regional mix as well as reduced tax rates for tight sand gas production related to South Texas Olmos and Eagle Ford completions.

Interest. Our gross interest cost in the first nine months of 2011 was $31.2 million, of which $5.7 million was capitalized. Our gross interest cost in the first nine months of 2010 was $30.3 million, of which $5.5 million was capitalized.

Income Taxes. Our effective income tax rate was 37.2% and 36.5% for the first nine months of 2011 and 2010, respectively. Our U.S. federal income tax returns for 2002 forward, our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2004, and our Texas franchise tax returns after 2006 remain subject to examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

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

Net Income. Our net income for the first nine months 2011 was $78.2 million, including $14.2 million from discontinued operations, which increased compared to our net income of $36.0 million for the first nine months of 2010.

Known Price Trends and Uncertainties

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

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

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

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

Liquidity and Capital Resources

Capital Expenditures

2011 Capital Expenditures Incurred. Our capital expenditures were $368.8 million in the first nine months of 2011 compared to $228.4 million spent in the same period of 2010. The increase of $140.4 million was mainly due to additional drilling and completion activity in our South Texas core region. These 2011 expenditures were primarily funded by $288.5 million of cash provided by operating activities and remaining cash proceeds from our stock offering in November 2010.

2011 Capital Expenditures Planned. We currently plan to finance the remainder of our 2011 accrual based capital expenditures with our 2011 cash flow, cash on hand, proceeds from our October 2011 asset divestiture and potential line of credit borrowings. Our 2011 capital expenditures are currently budgeted at $480 million to $520 million, which is net of disposition activity. Approximately 80% of our capital budget is targeted for our South Texas core region. The Company may enter into joint venture arrangements, pooling agreements for particular prospects, and consider non-strategic property dispositions, in each case to accelerate drilling and development of its assets and diversify its risk profile.

Sources of Funds

Net Cash Provided by Operating Activities. For the first nine months of 2011, our net cash provided by operating activities was $288.5 million, representing a 49% increase as compared to $193.7 million generated during the same period of 2010. The $94.8 million change was primarily due to higher oil prices along with a significant increase in natural gas production during the first nine months of 2011.

Existing Credit Facility. In May 2011 we renewed and extended our $500 million credit facility with a syndicate of ten banks through May 12, 2016, and have included a feature that allows the Company to increase the size of the aggregate facility to up to $700 million with additional commitments from the lenders and their consent, subject to the terms of the credit agreement. We also increased our borrowing base to $400 million from $300 million, while the commitment amount remains at $300 million, the limit on our borrowings without lender consent. Under the terms of the credit facility, we can increase the commitment amount to the total amount of the borrowing base with unanimous consent of the bank group as it might change from time to time. We had no amounts drawn under our credit facility as of September 30, 2011. In November 2011, in conjunction with our regularly scheduled borrowing base redetermination which occurs every six months, our borrowing base was reaffirmed at the current level and our commitment amount remains the same. Our revolving credit facility includes requirements to maintain certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of this agreement and expect to remain in compliance with these provisions in future periods. Our available borrowings under our line of credit facility provide us liquidity. In light of credit market volatility in recent years, which caused many financial institutions to experience liquidity issues, we periodically review the creditworthiness of the banks that fund our credit facility.

Financial Ratios

Working Capital and Debt to Capitalization Ratio. Our working capital decreased from a surplus of $1.6 million at December 31, 2010, to a deficit of $110.9 million at September 30, 2011. The change primarily resulted from a decrease in cash and cash equivalents as we used cash received from our equity offering in 2010 to fund ongoing operations including our 2011 capital program. Working capital, which is calculated as current assets less current liabilities, can be used to measure both a company's operational efficiency and short-term financial health. The Company uses this measure to track our short-term financial position. Not included in our working capital ratio is available liquidity through our credit facility. Our debt to capitalization ratio decreased to 33% at September 30, 2011, as compared to 35% at December 31, 2010, primarily due to the increase in retained earnings from our 2011 net income.

Contractual Commitments and Obligations

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

Critical Accounting Policies and New Accounting Pronouncements

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

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

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

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

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using the preceding 12-months' average price based on closing prices on the first day of each month, adjusted for price differentials and the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). We did not have any outstanding derivative instruments at September 30, 2011 that materially affect this calculation.

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

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

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

Forward-Looking Statements

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. We do not utilize these agreements and financial instruments for trading and only enter into derivative agreements with banks in our credit facility. At September 30, 2011, we did not have any outstanding derivative instruments in place for future production.

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

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

## Item 4. Controls and Procedures

### Disclosure Controls and Procedures

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

### Internal Control Over Financial Reporting

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

## PART II. - OTHER INFORMATION

### Item 1. Legal Proceedings.

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

### Item 1A. Risk Factors.

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

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

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

| Period | Total Number of Shares Purchased | Average Price Paid Per Share | Total Number of shares Purchased as Part of Publicly Announced Plans or Programs | Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands) |
|---|---|---|---|---|
| 07/01/11 – 07/31/11 (1) | 198 | $ 40.56 | --- | $ --- |
| 08/01/11 – 08/31/11 (1) | 114 | $ 30.96 | --- | --- |
| 09/01/11 – 09/30/11 (1) | 664 | $ 27.50 | --- | --- |
| Total | 976 | $ 30.55 | --- | $ --- |

(1) These shares were withheld from employees to satisfy tax obligations arising upon the vesting of restricted shares.

### Item 3. Defaults Upon Senior Securities.

None.

### Item 5. Other Information.

None.

### Item 6. Exhibits.

31.1*

| | |
|---|---|
| | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2* | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32* | Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |

*Filed herewith

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: November 3, 2011 | By: | /s/ Alton D. Heckaman, Jr.<br>Alton D. Heckaman, Jr.<br>Executive Vice President and<br>Chief Financial Officer |
| Date: November 3, 2011 | By: | /s/ Barry S. Turcotte<br>Barry S. Turcotte<br>Vice President, Controller and Principal<br>Accounting Officer |

Exhibit Index

31.1* Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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32* Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*Filed herewith