MURPHY OIL CORP /DE
Form 10-Q
August 05, 2014
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# UNITED STATES

# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-Q

**(Mark one)**

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the quarterly period ended June 30, 2014**

**OR**

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from _________ to _________**

**Commission File Number 1-8590**

# MURPHY OIL CORPORATION

**(Exact name of registrant as specified in its charter)**

| | |
|---|---|
| **Delaware** | **71-0361522** |
| **(State or other jurisdiction of incorporation or organization)** | **(I.R.S. Employer Identification Number)** |
| **200 Peach Street** | |
| **P.O. Box 7000, El Dorado, Arkansas** | **71731-7000** |
| **(Address of principal executive offices)** | **(Zip Code)** |

**(870) 862-6411**

**(Registrant s telephone number, including area code)**

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 (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. x Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). x Yes ¨ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange act.

| | | | |
|---|---|---|---|
| Large accelerated filer | x | Accelerated filer | ¨ |
| Non-accelerated filer | ¨ | Smaller reporting company | ¨ |

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

Number of shares of Common Stock, $1.00 par value, outstanding at June 30, 2014 was **177,571,522.**

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**MURPHY OIL CORPORATION**

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**PART I FINANCIAL INFORMATION**

***ITEM 1. FINANCIAL STATEMENTS***

Murphy Oil Corporation and Consolidated Subsidiaries

**CONSOLIDATED BALANCE SHEETS**

(Thousands of dollars)

| | (Unaudited) June 30, 2014 | December 31, 2013 |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 661,086 | 750,155 |
| Canadian government securities with maturities greater than 90 days at the date of acquisition | 427,372 | 374,842 |
| Accounts receivable, less allowance for doubtful accounts of $1,609 in 2014 and 2013 | 1,053,122 | 999,872 |
| Inventories, at lower of cost or market | | |
| Crude oil | 38,119 | 40,077 |
| Materials and supplies | 251,375 | 254,118 |
| Prepaid expenses | 125,046 | 83,856 |
| Deferred income taxes | 59,619 | 61,991 |
| Assets held for sale | 617,194 | 943,732 |
| Total current assets | 3,232,933 | 3,508,643 |
| Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $9,318,710 in 2014 and $8,540,239 in 2013 | 14,196,884 | 13,481,055 |
| Goodwill | 40,083 | 40,259 |
| Deferred charges and other assets | 101,883 | 98,123 |
| Assets held for sale | 302,151 | 381,404 |
| Total assets | $ 17,873,934 | 17,509,484 |
| **LIABILITIES AND STOCKHOLDERS EQUITY** | | |
| Current liabilities | | |
| Current maturities of long-term debt | $ 35,100 | 26,249 |
| Accounts payable and accrued liabilities | 2,257,458 | 2,335,712 |
| Income taxes payable | 302,028 | 222,930 |
| Liabilities associated with assets held for sale | 255,935 | 639,140 |
| Total current liabilities | 2,850,521 | 3,224,031 |
| Long-term debt, including capital lease obligation | 3,786,494 | 2,936,563 |
| Deferred income taxes | 1,507,484 | 1,466,100 |
| Asset retirement obligations | 905,467 | 852,488 |
| Deferred credits and other liabilities | 331,144 | 339,028 |
| Liabilities associated with assets held for sale | 93,927 | 95,544 |
| Stockholders equity | | |
| Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued | 0 | 0 |
| Common Stock, par $1.00, authorized 450,000,000 shares, issued 195,017,103 shares in 2014 and 194,920,155 shares in 2013 | 195,017 | 194,920 |
| Capital in excess of par value | 886,292 | 902,633 |
| Retained earnings | 8,231,331 | 8,058,792 |
| Accumulated other comprehensive income | 172,531 | 172,119 |

| | | |
|---|---|---|
| Treasury stock, 17,445,581 shares of Common Stock in 2014 and 11,513,642 shares of Common Stock in 2013, at cost | (1,086,274) | (732,734) |
| Total stockholders equity | 8,398,897 | 8,595,730 |
| Total liabilities and stockholders equity | $ 17,873,934 | 17,509,484 |

See Notes to Consolidated Financial Statements, page 7.

The Exhibit Index is on page 36.

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Murphy Oil Corporation and Consolidated Subsidiaries

**CONSOLIDATED STATEMENTS OF INCOME (unaudited)**

(Thousands of dollars, except per share amounts)

| | Three Months Ended June 30, 2014 | Three Months Ended June 30, 2013* | Six Months Ended June 30, 2014 | Six Months Ended June 30, 2013* |
|---|---|---|---|---|
| **REVENUES** | | | | |
| Sales and other operating revenues | $ 1,357,905 | 1,315,600 | 2,639,113 | 2,614,526 |
| Interest and other income (loss) | (8,884) | 16,386 | (3,692) | 8,398 |
| Total revenues | 1,349,021 | 1,331,986 | 2,635,421 | 2,622,924 |
| **COSTS AND EXPENSES** | | | | |
| Lease operating expenses | 285,865 | 251,775 | 548,120 | 588,998 |
| Severance and ad valorem taxes | 28,893 | 20,334 | 55,219 | 35,397 |
| Exploration expenses, including undeveloped lease amortization | 134,812 | 88,772 | 273,278 | 197,265 |
| Selling and general expenses | 95,000 | 86,904 | 187,026 | 168,371 |
| Depreciation, depletion and amortization | 458,993 | 381,384 | 855,242 | 744,526 |
| Impairment of assets | 0 | 21,587 | 0 | 21,587 |
| Accretion of asset retirement obligations | 12,327 | 11,961 | 24,392 | 23,857 |
| Interest expense | 33,769 | 29,593 | 66,655 | 56,621 |
| Interest capitalized | (5,053) | (14,478) | (13,921) | (27,866) |
| Other expense | (178) | 0 | 636 | 0 |
| Total costs and expenses | 1,044,428 | 877,832 | 1,996,647 | 1,808,756 |
| Income from continuing operations before income taxes | 304,593 | 454,154 | 638,774 | 814,168 |
| Income tax expense | 161,925 | 194,265 | 326,820 | 371,596 |
| Income from continuing operations | 142,668 | 259,889 | 311,954 | 442,572 |
| Income (loss) from discontinued operations, net of taxes | (13,256) | 142,755 | (27,289) | 320,671 |
| **NET INCOME** | $ 129,412 | 402,644 | 284,665 | 763,243 |
| **PER COMMON SHARE BASIC** | | | | |
| Income from continuing operations | $ 0.80 | 1.38 | 1.73 | 2.33 |
| Income (loss) from discontinued operations | (0.08) | 0.75 | (0.15) | 1.69 |
| Net income | $ 0.72 | 2.13 | 1.58 | 4.02 |
| **PER COMMON SHARE DILUTED** | | | | |
| Income from continuing operations | $ 0.79 | 1.37 | 1.72 | 2.32 |
| Income (loss) from discontinued operations | (0.07) | 0.75 | (0.15) | 1.68 |
| Net income | $ 0.72 | 2.12 | 1.57 | 4.00 |
| Average common shares outstanding | | | | |
| Basic | 178,500,440 | 189,002,146 | 180,003,605 | 189,753,673 |
| Diluted | 180,045,020 | 189,944,793 | 181,327,914 | 190,702,248 |

* Reclassified to conform to current presentation See Note D.
See Notes to Consolidated Financial Statements, page 7.

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Murphy Oil Corporation and Consolidated Subsidiaries

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (unaudited)**

(Thousands of dollars)

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| Net income | $ 129,412 | 402,644 | 284,665 | 763,243 |
| Other comprehensive income (loss), net of tax | | | | |
| Net gain (loss) from foreign currency translation | 133,559 | (117,254) | (3,045) | (235,008) |
| Retirement and postretirement benefit plans | 1,026 | 4,532 | 2,491 | 7,270 |
| Deferred loss on interest rate hedges reclassified to interest expense | 483 | 484 | 966 | 970 |
| Other comprehensive income (loss) | 135,068 | (112,238) | 412 | (226,768) |
| **COMPREHENSIVE INCOME** | $ 264,480 | 290,406 | 285,077 | 536,475 |

See Notes to Consolidated Financial Statements, page 7.

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Murphy Oil Corporation and Consolidated Subsidiaries

**CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)**

(Thousands of dollars)

| | Six Months Ended June 30, 2014 | Six Months Ended June 30, 2013[1] |
|---|---|---|
| **OPERATING ACTIVITIES** | | |
| Net income | $ 284,665 | 763,243 |
| Adjustments to reconcile net income to net cash provided by operating activities | | |
| Loss (income) from discontinued operations | 27,289 | (320,671) |
| Depreciation, depletion and amortization | 855,242 | 744,526 |
| Impairment of assets | 0 | 21,587 |
| Amortization of deferred major repair costs | 4,313 | 4,415 |
| Dry hole costs | 127,827 | 81,305 |
| Amortization of undeveloped leases | 37,764 | 32,052 |
| Accretion of asset retirement obligations | 24,392 | 23,857 |
| Deferred and noncurrent income tax charges | 18,122 | 72,745 |
| Pretax loss from disposition of assets | 4,997 | 224 |
| Net (increase) decrease in noncash operating working capital | 48,449 | (131,812) |
| Other operating activities, net | 22,106 | (22,487) |
| Net cash provided by continuing operations | 1,455,166 | 1,268,984 |
| Net cash provided by discontinued operations | 4,517 | 400,026 |
| Net cash provided by operating activities | 1,459,683 | 1,669,010 |
| **INVESTING ACTIVITIES** | | |
| Property additions and dry hole costs[2] | (1,840,544) | (1,853,902) |
| Proceeds from sales of assets | 3,089 | 130 |
| Purchase of investment securities[3] | (372,861) | (373,196) |
| Proceeds from maturity of investment securities[3] | 320,331 | 358,915 |
| Investing activities of discontinued operations | | |
| Sales proceeds | 0 | 282,202 |
| Property additions and other | (9,092) | (122,807) |
| Other net | (13,007) | 1,718 |
| Net cash required by investing activities | (1,912,084) | (1,706,940) |
| **FINANCING ACTIVITIES** | | |
| Borrowings of long-term debt[2] | 850,000 | 461,978 |
| Purchase of treasury stock | (375,000) | (250,000) |
| Proceeds from exercise of stock options and employee stock purchase plans | 0 | 2,628 |
| Withholding tax on stock-based incentive awards | (6,784) | (8,966) |
| Cash dividends paid | (112,126) | (119,376) |
| Other net | (1,224) | (2,724) |
| Net cash provided by financing activities | 354,866 | 83,540 |
| Effect of exchange rate changes on cash and cash equivalents | 8,466 | (18,500) |

| | | |
|---|---|---|
| Net increase (decrease) in cash and cash equivalents | (89,069) | 27,110 |
| Cash and cash equivalents at January 1 | 750,155 | 947,316 |
| Cash and cash equivalents at June 30 | $ 661,086 | 974,426 |

[1] Reclassified to conform to current presentation See Note D.

[2] Excludes non-cash asset and long-term obligation of $356,170 in 2013 associated with lease commencement for production equipment at the Kakap field offshore Malaysia.

[3] Investments are Canadian government securities with maturities greater than 90 days at the date of acquisition.

See Notes to Consolidated Financial Statements, page 7.

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Murphy Oil Corporation and Consolidated Subsidiaries

**CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY (unaudited)**

(Thousands of dollars)

| | Six Months Ended June 30, 2014 | 2013 |
|---|---|---|
| **Cumulative Preferred Stock** par $100, authorized 400,000 shares, none issued | 0 | 0 |
| **Common Stock** par $1.00, authorized 450,000,000 shares, issued 195,017,103 at June 30, 2014 and 194,770,571 shares at June 30, 2013 | | |
| Balance at beginning of period | $ 194,920 | 194,616 |
| Exercise of stock options | 97 | 155 |
| Balance at end of period | 195,017 | 194,771 |
| **Capital in Excess of Par Value** | | |
| Balance at beginning of period | 902,633 | 873,934 |
| Exercise of stock options, including income tax benefits | (11,232) | 1,928 |
| Restricted stock transactions and other | (27,970) | (24,485) |
| Stock-based compensation | 22,884 | 30,327 |
| Other | (23) | (87) |
| Balance at end of period | 886,292 | 881,617 |
| **Retained Earnings** | | |
| Balance at beginning of period | 8,058,792 | 7,717,389 |
| Net income for the period | 284,665 | 763,243 |
| Cash dividends | (112,126) | (119,376) |
| Balance at end of period | 8,231,331 | 8,361,256 |
| **Accumulated Other Comprehensive Income** | | |
| Balance at beginning of period | 172,119 | 408,901 |
| Foreign currency translation loss, net of income taxes | (3,045) | (235,008) |
| Retirement and postretirement benefit plans, net of income taxes | 2,491 | 7,270 |
| Deferred loss on interest rate hedges reclassified to interest expense, net of income taxes | 966 | 970 |
| Balance at end of period | 172,531 | 182,133 |
| **Treasury Stock** | | |
| Balance at beginning of period | (732,734) | (252,805) |
| Purchase of treasury shares | (375,000) | (250,000) |
| Sale of stock under employee stock purchase plans | 275 | 655 |
| Awarded restricted stock, net of forfeitures | 21,185 | 16,545 |
| Balance at end of period | (1,086,274) | (485,605) |
| **Total Stockholders Equity** | $ 8,398,897 | 9,134,172 |

See notes to Consolidated Financial Statements, page 7

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*NOTES TO CONSOLIDATED FINANCIAL STATEMENTS*

These notes are an integral part of the financial statements of Murphy Oil Corporation and Consolidated Subsidiaries (Murphy/the Company) on pages 2 through 6 of this Form 10-Q report.

**Note A Interim Financial Statements**

The consolidated financial statements of the Company presented herein have not been audited by independent auditors, except for the Consolidated Balance Sheet at December 31, 2013. In the opinion of Murphy s management, the unaudited financial statements presented herein include all accruals necessary to present fairly the Company s financial position at June 30, 2014, and the results of operations, cash flows and changes in stockholders equity for the three-month and six-month periods ended June 30, 2014 and 2013, in conformity with accounting principles generally accepted in the United States of America (U.S.). In preparing the financial statements of the Company in conformity with accounting principles generally accepted in the U.S., management has made a number of estimates and assumptions related to the reporting of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities. Actual results may differ from the estimates.

Financial statements and notes to consolidated financial statements included in this Form 10-Q report should be read in conjunction with the Company s 2013 Form 10-K report, as certain notes and other pertinent information have been abbreviated or omitted in this report. Financial results for the three-month and six-month periods ended June 30, 2014 are not necessarily indicative of future results.

**Note B Property, Plant and Equipment**

Under U.S. generally accepted accounting principles for companies that use the successful efforts method of accounting, exploratory well costs should continue to be capitalized when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

At June 30, 2014, the Company had total capitalized exploratory well costs pending the determination of proved reserves of $396.4 million. The following table reflects the net changes in capitalized exploratory well costs during the six-month periods ended June 30, 2014 and 2013.

| (Thousands of dollars) | 2014 | 2013 |
|---|---|---|
| Beginning balance at January 1 | $ 393,030 | 445,697 |
| Additions pending the determination of proved reserves | 3,376 | 27,129 |
| Reclassifications to proved properties based on the determination of proved reserves | 0 | (28,398) |
| Balance at June 30 | $ 396,406 | 444,428 |

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed for each individual well and the number of projects for which exploratory well costs have been capitalized. The projects are aged based on the last well drilled in the project.

| | June 30, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | | | 2013 | | |
| (Thousands of dollars) | Amount | No. of Wells | No. of Projects | Amount | No. of Wells | No. of Projects |
| Aging of capitalized well costs: | | | | | | |
| Zero to one year | $ 32,192 | 2 | 1 | $ 49,994 | 3 | 1 |
| One to two years | 50,333 | 3 | 1 | 37,898 | 5 | 1 |
| Two to three years | 37,969 | 5 | 0 | 73,863 | 7 | 3 |
| Three years or more | 275,912 | 22 | 7 | 282,673 | 26 | 5 |
| | $ 396,406 | 32 | 9 | $ 444,428 | 41 | 10 |

Of the $364.2 million of exploratory well costs capitalized more than one year at June 30, 2014, $214.2 million is in Malaysia, $116.3 million is in the U.S. and $33.7 million is in Brunei. In all three geographical areas, either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion.

See also Note E for discussion regarding a capital lease of production equipment at the Kakap field.

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***NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)***

**Note C Inventories**

Inventories are carried at the lower of cost or market. For the Company s U.K. refining and marketing operations reported as discontinued operations, the cost of crude oil and finished products is predominantly determined on the last-in, first-out (LIFO) method. At June 30, 2014 and December 31, 2013, the carrying value of inventories under the LIFO method was $161.2 million and $268.6 million, respectively, less than such inventories would have been valued using the first-in, first-out (FIFO) method. These inventories are included in assets held for sale on the Consolidated Balance Sheet.

**Note D Discontinued Operations**

The Company has previously announced its intention to sell its U.K. refining and marketing operations. The Company has accounted for this U.K. downstream business as discontinued operations for all periods presented, including a reclassification of 2013 operating results and cash flows for this business to discontinued operations. The U.K. downstream operations were previously reported as a separate segment within the Company s former refining and marketing business. On July 31, 2014, Murphy signed an agreement to sell the Milford Haven, Wales, refinery and terminal assets. Pending regulatory approval and subject to other material conditions, this transaction is scheduled to be completed by October 31, 2014. Additionally, a separate transaction for sale of the U.K. retail marketing business is at an advanced stage.

On August 30, 2013, Murphy Oil Corporation (the Company ) distributed 100% of the outstanding common stock of Murphy USA Inc. ( MUSA ) to its shareholders in a generally tax-free spin-off for U.S. federal income tax purposes. Prior to the separation, MUSA held all of the Company s U.S. downstream operations, including retail gasoline stations and other marketing assets, plus two ethanol production facilities. The shares of MUSA common stock are traded on the New York Stock Exchange under the ticker symbol MUSA. The Company has no continuing involvement with MUSA operations. Accordingly, the operating results and the cash flows for these former U.S. downstream operations have been reported as discontinued operations in the 2013 consolidated financial statements. The U.S. downstream operations were previously reported as a separate segment within the Company s former refining and marketing business.

The Company also sold its oil and gas assets in the United Kingdom during 2013. After-tax gains on sale of the assets were $68.8 million in the three months ended June 30, 2013 and $216.2 million in the six months ended June 30, 2013. The Company has accounted for these U.K. upstream operations as discontinued operations in its consolidated financial statements for all periods presented.

The results of operations associated with these discontinued operations for the three-month and six-month periods ended June 30, 2014 and 2013 were as follows:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (Thousands of dollars) | 2014 | 2013 | 2014 | 2013 |
| Revenues | $ 811,134 | 5,964,045 | 2,243,520 | 11,479,583 |
| Income before income taxes, including pretax gain on disposals of $55,640 and $130,568 during the three-month and six-month periods in 2013 | $ (16,938) | 184,418 | (34,233) | 317,339 |
| Income tax expense (benefit) | (3,682) | 41,663 | (6,944) | (3,332) |
| Income (loss) from discontinued operations | $ (13,256) | 142,755 | (27,289) | 320,671 |

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***NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)***

***Note D Discontinued Operations (Contd.)***

The following table presents the carrying value of the major categories of assets and liabilities of U.K. refining and marketing operations reflected as held for sale on the Company s consolidated balance sheets at June 30, 2014 and December 31, 2013:

| (Millions of dollars) | June 30, 2014 | December 31, 2013 |
|---|---|---|
| Current assets | | |
| Cash | $ 242,438 | 301,302 |
| Accounts receivable | 165,972 | 302,059 |
| Inventories | 126,656 | 254,240 |
| Other | 82,128 | 86,131 |
| Total current assets held for sale | $ 617,194 | 943,732 |
| Non-current assets | | |
| Property, plant and equipment, net | $ 279,555 | 360,347 |
| Other | 22,596 | 21,057 |
| Total non-current assets held for sale | $ 302,151 | 381,404 |
| Current liabilities | | |
| Accounts payable | $ 255,470 | 637,432 |
| Other | 465 | 1,708 |
| Total current liabilities associated with assets held for sale | $ 255,935 | 639,140 |
| Non-current liabilities | | |
| Deferred income taxes payable | $ 75,896 | 68,096 |
| Deferred credits and other liabilities | 18,031 | 27,448 |
| Total non-current liabilities associated with assets held for sale | $ 93,927 | 95,544 |

**Note E Financing Arrangements and Debt**

The Company has a $2.0 billion committed credit facility that expires in June 2017. Borrowings under the facility bear interest at 1.25% above LIBOR based on the Company s current credit rating as of June 30, 2014. In addition, facility fees of 0.25% are charged on the full $2.0 billion commitment. The Company also has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through October 2015.

During June 2013, the Company and its partners entered into a 25-year lease of production equipment at the Kakap field offshore Malaysia. The lease has been accounted for as a capital lease, and payments under the agreement are to be made over a 15-year period through June 2028. Current maturities and long-term debt on the Consolidated Balance Sheet include $35.1 million and $341.7 million associated with this lease at June 30, 2014.

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***NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)***

**Note F Cash Flow Disclosures**

Additional disclosures regarding cash flow activities are provided below.

| (Thousands of dollars) | Six Months Ended June 30, 2014 | 2013 |
|---|---|---|
| Net (increase) decrease in operating working capital other than cash and cash equivalents: | | |
| Increase in accounts receivable | $ (53,133) | (367,478) |
| Decrease (increase) in inventories | 5,574 | (11,154) |
| Increase in prepaid expenses | (41,191) | (112,303) |
| Decrease in deferred income tax assets | 1,895 | 75,616 |
| Increase in accounts payable and accrued liabilities | 55,729 | 127,301 |
| Increase in current income tax liabilities | 79,575 | 156,206 |
| Total | $ 48,449 | (131,812) |
| Supplementary disclosures (including discontinued operations): | | |
| Cash income taxes paid | $ 234,071 | 196,923 |
| Interest paid, net of amounts capitalized | 41,922 | 25,010 |

**Note G Employee and Retiree Benefit Plans**

The Company has defined benefit pension plans that are principally noncontributory and cover most full-time employees. All pension plans are funded except for the U.S. and Canadian nonqualified supplemental plans and the U.S. directors plan. All U.S. tax qualified plans meet the funding requirements of federal laws and regulations. Contributions to foreign plans are based on local laws and tax regulations. The Company also sponsors health care and life insurance benefit plans, which are not funded, that cover most active and retired U.S. employees. Additionally, most U.S. retired employees are covered by a life insurance benefit plan. The health care benefits are contributory; the life insurance benefits are noncontributory.

Effective with the spin-off of Murphy s former U.S. retail marketing operation, Murphy USA Inc. (MUSA) on August 30, 2013, significant modifications were made to the U.S. defined benefit pension plan. Certain Murphy employees benefits under the U.S. plan were frozen at that time. No further benefit service will accrue for the affected employees; however, the plan will recognize future eligible earnings after the spin-off date. In addition, all previously unvested benefits became fully vested at the spin-off date. For those affected active employees of the Company, additional U.S. retirement plan benefits will accrue in future periods under a cash balance formula. Employees hired after August 30, 2013 will only accrue plan benefits under the cash balance formula. Upon the spin-off of MUSA, Murphy retained all vested pension defined benefit and other postretirement benefit obligations associated with current and former employees of this separated business. No additional benefit will accrue for any employees of MUSA under the Company s retirement plan after the spin-off date.

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*NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)*

**Note G Employee and Retiree Benefit Plans** ***(Contd.)***

The table that follows provides the components of net periodic benefit expense for the three-month and six-month periods ended June 30, 2014 and 2013.

| | Three Months Ended June 30, | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Postretirement Benefits | |
| (Thousands of dollars) | 2014 | 2013 | 2014 | 2013 |
| Service cost | $ 6,284 | 7,094 | 672 | 1,230 |
| Interest cost | 8,253 | 7,700 | 1,277 | 1,279 |
| Expected return on plan assets | (8,528) | (7,569) | 0 | 0 |
| Amortization of prior service cost | 228 | 303 | (20) | (44) |
| Amortization of transitional asset | 212 | 121 | 2 | 2 |
| Recognized actuarial loss | 1,733 | 4,759 | 59 | 473 |
| Net periodic benefit expense | $ 8,182 | 12,408 | 1,990 | 2,940 |

| | Six Months Ended June 30, | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Postretirement Benefits | |
| (Thousands of dollars) | 2014 | 2013 | 2014 | 2013 |
| Service cost | $ 12,840 | 14,697 | 1,344 | 2,397 |
| Interest cost | 16,468 | 14,131 | 2,555 | 2,513 |
| Expected return on plan assets | (17,008) | (13,269) | 0 | 0 |
| Amortization of prior service cost | 453 | 579 | (41) | (86) |
| Amortization of transitional asset | 420 | 241 | 3 | 4 |
| Recognized actuarial loss | 3,466 | 8,291 | 118 | 930 |
| Net periodic benefit expense | $ 16,639 | 24,670 | 3,979 | 5,758 |

During the six-month period ended June 30, 2014, the Company made contributions of $36.2 million to its defined benefit pension and postretirement benefit plans. Remaining funding in 2014 for the Company s defined benefit pension and postretirement plans is anticipated to be $15.6 million.

**Note H Incentive Plans**

The costs resulting from all share-based payment transactions are recognized as an expense in the Consolidated Statements of Income using a fair value-based measurement method over the periods that the awards vest.

The 2012 Annual Incentive Plan (2012 Annual Plan) authorizes the Executive Compensation Committee (the Committee) to establish specific performance goals associated with annual cash awards that may be earned by officers, executives and other key employees. Cash awards under the 2012 Annual Plan are determined based on the Company s actual financial and operating results as measured against the performance goals established by the Committee. The 2012 Long-Term Incentive Plan (2012 Long-Term Plan) authorizes the Committee to make grants of the Company s Common Stock and other stock-based incentives to employees. These grants may be in the form of stock options (nonqualified or incentive), stock appreciation rights (SAR), restricted stock, restricted stock units, performance units, performance shares, dividend equivalents and other stock-based incentives. The 2012 Long-Term Plan expires in 2022. A total of 8,700,000 shares are issuable during the life of the 2012

Long-Term Plan, with annual grants limited to 1% of Common shares outstanding. The Company has an Employee Stock Purchase Plan that permits the issuance of up to 980,000 shares through September 30, 2017. The Company also has a Stock Plan for Non-Employee Directors that permits the issuance of restricted stock and stock options or a combination thereof to the Company s Directors.

On February 4, 2014, the Committee granted stock options for 772,900 shares at an exercise price of $55.82 per share. The Black-Scholes valuation for these awards was $12.84 per option. The Committee also granted 464,300 performance-based restricted stock units (RSU) and 233,400 time-based RSU on that date. The fair value of the performance-based RSU, using a Monte Carlo valuation model, ranged from $33.90 to $51.30 per unit. The fair value

***NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)***

**Note H Incentive Plans *(Contd.)***

of time-based RSU was estimated based on the fair market value of the Company s stock on the date of grant, which was $55.82 per share. Additionally, on February 4, 2014, the Committee granted 183,200 SAR and 170,900 units of cash-settled RSU (RSU-C) to certain employees. The SAR and RSU-C are to be settled in cash, net of applicable income taxes, and are accounted for as liability-type awards. The initial fair value of these SAR was equivalent to the stock options granted, while the initial value of RSU-C was equivalent to equity-settled restricted stock units granted. On February 5, 2014, the Committee granted 43,848 shares of time-based RSU to the Company s Directors under the Non-employee Director Plan. These shares vest on the third anniversary of the date of grant. The fair value of these awards was estimated at $55.20 per unit.

Beginning January 1, 2014, all stock option exercises are non-cash transactions for the Company. The employee will receive net shares, after applicable withholding taxes, upon each exercise. Cash received from options exercised under all share-based payment arrangements for the six-month period ended June 30, 2013 was $2.6 million. The actual income tax benefit realized for the tax deductions from option exercises of the share-based payment arrangements totaled $3.1 million and $3.0 million for the six-month periods ended June 30, 2014 and 2013, respectively.

Amounts recognized in the financial statements with respect to share-based plans are as follows:

| | Six Months Ended June 30, | |
|---|---|---|
| (Thousands of dollars) | 2014 | 2013 |
| Compensation charged against income before tax benefit | $ 32,142 | 35,142 |
| Related income tax benefit recognized in income | 9,978 | 7,246 |

**Note I Earnings per Share**

Net income was used as the numerator in computing both basic and diluted income per Common share for the three-month and six-month periods ended June 30, 2014 and 2013. The following table reconciles the weighted-average shares outstanding used for these computations.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (Weighted-average shares) | 2014 | 2013 | 2014 | 2013 |
| Basic method | 178,500,440 | 189,002,146 | 180,003,605 | 189,753,673 |
| Dilutive stock options and restricted stock units | 1,544,580 | 942,647 | 1,324,309 | 948,575 |
| Diluted method | 180,045,020 | 189,944,793 | 181,327,914 | 190,702,248 |

The following table reflects certain options to purchase shares of common stock that were outstanding during the 2014 and 2013 periods but were not included in the computation of diluted EPS above because the incremental shares from assumed conversion were antidilutive.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |

| | | | | |
|---|---|---|---|---|
| Antidilutive stock options excluded from diluted shares | 1,161,442 | 1,731,425 | 1,810,012 | 1,414,286 |
| Weighted average price of these options | $ 60.02 | $ 63.52 | $ 58.90 | $ 64.39 |

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*NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)*

**Note J Income Taxes**

The Company s effective income tax rate generally exceeds the statutory U.S. tax rate of 35%. The effective tax rate is calculated as the amount of income tax expense divided by income before income tax expense. For the three-month and six-month periods in 2014 and 2013, the Company s effective income tax rates were as follows:

| | 2014 | 2013 |
|---|---|---|
| Three months ended June 30 | 53.2% | 42.8% |
| Six months ended June 30 | 51.2% | 45.6% |

The effective tax rates for the periods presented exceeded the U.S. statutory tax rate of 35% due to several factors, including: the effects of income generated in foreign tax jurisdictions, certain of which have income tax rates that are higher than the U.S. Federal rate; U.S. state tax expense; and certain expenses, including exploration and other expenses in certain foreign jurisdictions, for which no income tax benefits are available or are not presently being recorded due to a lack of reasonable certainty of adequate future revenue against which to utilize these expenses as deductions.

The Company s tax returns in multiple jurisdictions are subject to audit by taxing authorities. These audits often take years to complete and settle. Although the Company believes that recorded liabilities for unsettled issues are adequate, additional gains or losses could occur in future years from resolution of outstanding unsettled matters. As of June 30, 2014, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States 2010; Canada 2008; United Kingdom 2011; and Malaysia 2006.

**Note K Financial Instruments and Risk Management**

Murphy utilizes derivative instruments to manage certain risks related to commodity prices, foreign currency exchange rates and interest rates. The use of derivative instruments for risk management is covered by operating policies and is closely monitored by the Company s senior management. The Company does not hold any derivatives for speculative purposes, and it does not use derivatives with leveraged or complex features. Derivative instruments are traded primarily with creditworthy major financial institutions or over national exchanges. The Company has a risk management control system to monitor commodity price risks and any derivatives obtained to manage a portion of such risks. For accounting purposes, the Company has not designated commodity and foreign currency derivative contracts as hedges, and therefore, it recognizes all unrealized gains and losses on these derivative contracts in its Consolidated Statements of Income. Certain interest rate derivative contracts were accounted for as hedges and the loss associated with settlement of these contracts was deferred in Accumulated Other Comprehensive Income. This loss is being reclassified to Interest Expense in the Consolidated Statements of Income over the period until the associated notes mature in 2022.

*Commodity Purchase Price Risks*

The Company is subject to commodity price risk related to crude oil it will produce and sell in 2014. The Company has entered into a series of West Texas Intermediate (WTI) crude oil fixed-price swap financial contracts covering a portion of its Eagle Ford Shale production from July 2014 through December 2014. Under these contracts, which mature monthly, the Company will pay the average monthly price in effect and will receive the fixed contract prices. WTI open contracts at June 30, 2014 were as follows:

| Dates | Volumes (barrels per day) | Swap Prices |
|---|---|---|
| July September 2014 | 26,000 | $ 94.89 per barrel |
| October December 2014 | 16,000 | $ 92.33 per barrel |

The fair value of these open commodity derivative contracts was a net liability of $36.9 million at June 30, 2014.

*Foreign Currency Exchange Risks*

The Company is subject to foreign currency exchange risk associated with operations in countries outside the United States. Short-term derivative instruments were outstanding at June 30, 2013 to manage the risk of certain future income taxes that are payable in Malaysian ringgits. The equivalent U.S. dollars of Malaysian ringgit derivative contracts open at June 30, 2013 were approximately $153.4 million. There were no open ringgit contracts at June 30, 2014. Short-term derivative instrument contracts totaling $33.0 million and $48.0 million U.S. dollars were also outstanding at June 30, 2014 and 2013, respectively, to manage the risk of certain U.S. dollar accounts receivable associated with sale of crude oil production in Canada. The impact from marking to market these foreign currency derivative contracts increased income before taxes by $0.7 million for the six-month period ended June 30, 2014 and reduced income before taxes by $5.6 million for the six-month period ended June 30, 2013.

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***NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)***

**Note K Financial Instruments and Risk Management *(Contd.)***

At June 30, 2014 and December 31, 2013, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

| (Thousands of dollars) | June 30, 2014 Asset (Liability) Derivatives | | December 31, 2013 Asset (Liability) Derivatives | |
|---|---|---|---|---|
| Type of Derivative Contract | Balance Sheet Location | Fair Value | Balance Sheet Location | Fair Value |
| Commodity | Accounts payable | $ (36,926) | Accounts receivable | $ 1,970 |
| Foreign exchange | Accounts receivable | 650 | Accounts payable | (1,038) |

For the three-month and six-month periods ended June 30, 2014 and 2013, the gains and losses recognized in the Consolidated Statements of Income for derivative instruments not designated as hedging instruments are presented in the following table.

| | | Gain (Loss) | | | |
|---|---|---|---|---|---|
| (Thousands of dollars) | Statement of Income | Three Months Ended June 30, | | Six Months Ended June 30, | |
| Type of Derivative Contract | Location | 2014 | 2013 | 2014 | 2013 |
| Commodity | Crude oil and product purchases | $ (36,041) | 0 | (54,455) | 0 |
| Commodity | Discontinued operations | 0 | 2,834 | 0 | (1,376) |
| Foreign exchange | Interest and other income | 1,464 | (1,328) | 4,900 | (4,146) |
| | | $ (34,577) | 1,506 | (49,555) | (5,522) |

*Interest Rate Risks*

In 2011 the Company entered into a series of derivative contracts known as forward starting interest rate swaps to manage interest rate risk associated with $350 million of 10-year notes that were sold in May 2012. These interest rate swaps matured in May 2012. Under hedge accounting rules, the Company deferred a loss on these contracts to match the payment of interest on these notes through 2022. During each of the six-month periods ended June 30, 2014 and 2013, $1.5 million of the deferred loss on the interest rate swaps was charged to income as a component of Interest Expense. The remaining loss deferred on these matured contracts at June 30, 2014 was $23.4 million, which is recorded, net of income taxes of $8.2 million, in Accumulated Other Comprehensive Income in the Consolidated Balance Sheet. The Company expects to charge approximately $1.5 million of this deferred loss to income in the form of interest expense during the remaining six months of 2014.

The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheets. The fair value hierarchy is based on the quality of inputs used to measure fair value, with Level 1 being the highest quality and Level 3 being the lowest quality. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs which reflect assumptions about pricing by market participants.

The carrying value of assets and liabilities recorded at fair value on a recurring basis at June 30, 2014 and December 31, 2013 are presented in the following table.

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*NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)*

**Note K Financial Instruments and Risk Management *(Contd.)***

| | June 30, 2014 | | | | December 31, 2013 | | | |
|---|---|---|---|---|---|---|---|---|
| (Thousands of dollars) | Level 1 | Level 2 | Level 3 | Total | Level 1 | Level 2 | Level 3 | Total |
| Assets | | | | | | | | |
| Foreign currency exchange derivative contracts | $ 0 | 650 | 0 | 650 | 0 | 0 | 0 | 0 |
| Commodity derivative contracts | 0 | 0 | 0 | 0 | 0 | 1,970 | 0 | 1,970 |
| | $ 0 | 650 | 0 | 650 | 0 | 1,970 | 0 | 1,970 |
| Liabilities | | | | | | | | |
| Nonqualified employee savings plans | $ 14,439 | 0 | 0 | 14,439 | 13,267 | 0 | 0 | 13,267 |
| Commodity derivative contracts | 0 | 36,926 | 0 | 36,926 | 0 | 0 | 0 | 0 |
| Foreign currency exchange derivative contracts | 0 | 0 | 0 | 0 | 0 | 1,038 | 0 | 1,038 |
| | $ 14,439 | 36,926 | 0 | 51,365 | 13,267 | 1,038 | 0 | 14,305 |

The fair value of West Texas Intermediate (WTI) crude oil derivative contracts was determined based on active market quotes for WTI crude oil at the balance sheet dates. The fair value of foreign exchange derivative contracts was based on market quotes for similar contracts at the balance sheet dates. The income effect of changes in the fair value of crude oil derivative contracts is recorded in Sales and Other Operating Revenues in the Consolidated Statements of Income and changes in fair value of foreign exchange derivative contracts is recorded in Interest and Other Income. The nonqualified employee savings plan is an unfunded savings plan through which participants seek a return via phantom investments in equity securities and/or mutual funds. The fair value of this liability was based on quoted prices for these equity securities and mutual funds. The income effect of changes in the fair value of the nonqualified employee savings plan is recorded in Selling and General Expenses in the Consolidated Statements of Income.

The Company offsets certain assets and liabilities related to derivative contracts when the legal right of offset exists. There were no offsetting positions recorded at June 30, 2014 and December 31, 2013.

**Note L Accumulated Other Comprehensive Income**

The components of Accumulated Other Comprehensive Income (AOCI) on the Consolidated Balance Sheets at December 31, 2013 and June 30, 2014 and the changes during the six-month period ended June 30, 2014 are presented net of taxes in the following table.

| (Thousands of dollars) | Foreign Currency Translation Gains (Losses)[1] | Retirement and Postretirement Benefit Plan Adjustments[1] | Deferred Loss on Interest Rate Derivative Hedges[1] | Total[1] |
|---|---|---|---|---|
| Balance at December 31, 2013 | $ 305,192 | (116,956) | (16,117) | 172,119 |
| Components of other comprehensive income (loss): | | | | |
| Before reclassifications to income | (3,045) | 31 | 0 | (3,014) |
| Reclassifications to income | 0 | 2,460[2] | 966[3] | 3,426 |
| Net other comprehensive income (loss) | (3,045) | 2,491 | 966 | 412 |

| | | | | | |
|---|---|---|---|---|---|
| Balance at June 30, 2014 | $ | 302,147 | (114,465) | (15,151) | 172,531 |

[1] All amounts are presented net of income taxes.

[2] Reclassifications before taxes of $3,758 for the six-month period ended June 30, 2014 are included in the computation of net periodic benefit expense. See Note G for additional information. Related income taxes of $1,298 for the six-month period ended June 30, 2014 are included in Income tax expense.

[3] Reclassifications before taxes of $1,482 for the six-month period ended June 30, 2014 are included in Interest expense. Related income taxes of $516 for the six-month period ended June 30, 2014 are included in Income tax expense.

*NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)*

**Note M Environmental and Other Contingencies**

The Company s operations and earnings have been and may be affected by various forms of governmental action both in the United States and throughout the world. Examples of such governmental action include, but are by no means limited to: tax increases and retroactive tax claims; royalty and revenue sharing increases; import and export controls; price controls; currency controls; allocation of supplies of crude oil and petroleum products and other goods; expropriation of property; restrictions and preferences affecting the issuance of oil and gas or mineral leases; restrictions on drilling and/or production; laws and regulations intended for the promotion of safety and the protection and/or remediation of the environment; governmental support for other forms of energy; and laws and regulations affecting the Company s relationships with employees, suppliers, customers, stockholders and others. Because governmental actions are often motivated by political considerations and may be taken without full consideration of their consequences, and may be taken in response to actions of other governments, it is not practical to attempt to predict the likelihood of such actions, the form the actions may take or the effect such actions may have on the Company.

Murphy and other companies in the oil and gas industry are subject to numerous federal, state, local and foreign laws and regulations dealing with the environment. Violation of federal or state environmental laws, regulations and permits can result in the imposition of significant civil and criminal penalties, injunctions and construction bans or delays. A discharge of hazardous substances into the environment could, to the extent such event is not insured, subject the Company to substantial expense, including both the cost to comply with applicable regulations and claims by neighboring landowners and other third parties for any personal injury and property damage that might result.

The Company currently owns or leases, and has in the past owned or leased, properties at which hazardous substances have been or are being handled. Although the Company has used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under Murphy s control. Under existing laws the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. Certain of these historical properties are in various stages of negotiation, investigation, and/or cleanup and the Company is investigating the extent of any such liability and the availability of applicable defenses. The Company has retained certain liabilities related to environmental matters at formerly owned U.S. refineries that were sold in 2011. The Company also obtained insurance covering certain levels of environmental exposures related to past operations of these refineries. The Company believes costs related to these sites will not have a material adverse affect on Murphy s net income, financial condition or liquidity in a future period.

The U.S. Environmental Protection Agency (EPA) formerly considered the Company to be a Potentially Responsible Party (PRP) at one Superfund site. Based on evidence provided by the Company, the EPA has determined that the Company is no longer considered a PRP at this site.

There is the possibility that environmental expenditures could be required at currently unidentified sites, and new or revised regulations could require additional expenditures at known sites. However, based on information currently available to the Company, the amount of future remediation costs incurred at known or currently unidentified sites is not expected to have a material adverse effect on the Company s future net income, cash flows or liquidity.

Murphy and its subsidiaries are engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business. Based on information currently available to the Company, the ultimate resolution of these matters is not expected to have a material adverse effect on the Company s net income, financial condition or liquidity in a future period.

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*NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)*

**Note N  Commitments**

The Company has entered into forward sales contracts to mitigate the price risk for a portion of its 2014 heavy oil and 2014 through 2016 natural gas sales volumes in Western Canada. The heavy oil blend sales contracts call for deliveries of 4,000 barrels per day in July through December 2014 that achieve netback values that average Cdn$54.89 per barrel. The natural gas contracts call for deliveries from July through December 2014 that average approximately 110 million cubic feet per day at prices averaging Cdn$4.04 per MCF, with the contracts calling for delivery at the NOVA inventory transfer sales point. The Company also has natural gas sales contracts calling for deliveries in 2015 and 2016 of approximately 65 million cubic feet per day and 10 million cubic feet per day, respectively, at prices that average Cdn$4.13 per MCF. These oil and natural gas contracts have been accounted for as normal sales for accounting purposes.

**Note O  New Accounting Principles**

In May 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) addressing recognition of revenue from contracts with customers. When adopted, this guidance will supersede current revenue recognition rules currently followed by the Company. The core principle of the new ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The ASU provides five steps for an entity to apply in recognizing revenue, including: (1) identify the customer contract; (2) identify the contractual performance obligations; (3) determine the transaction price; (4) allocate the transaction price to the contractual performance obligations; and (5) recognize revenue when the performance obligation is satisfied. The new ASU also requires additional disclosures regarding significant contracts with customers. The new ASU will be effective for the Company on January 1, 2017, and early adoption is not permitted. For transition purposes, the new ASU permits either (a) a retrospective application to all years presented, or (b) an alternative transition method whereby the new guidance is only applied to contracts not completed at the date of initial application. The vast majority of the Company s revenue is recognized when oil and natural gas produced by the Company is delivered and legal ownership of these products has transferred to the purchaser. Based on the Company s present understanding, the accounting for oil and gas sales revenue is not expected to be significantly altered by the new ASU. The Company has not yet selected which transition method it will use.

In April 2014, the FASB issued an ASU that will change the requirements for reporting discontinued operations after its adoption. Under the new guidance, only disposals of components of an entity that represent a strategic shift that has or will have a major effect on an entity s operations and financial results will be reported as discontinued operations in the financial statements. Under prior guidance, a component of an entity that is a reportable segment, an operating segment, a reporting unit, a subsidiary, or an asset group that has been or will be eliminated from ongoing operations and for which the Company will not have any significant continuing involvement with the component after the disposal was generally reported as discontinued operations. The FASB anticipates that fewer component disposals will be reported as discontinued operations under the new guidance. The new guidance also requires expanded disclosures about discontinued operations. The new guidance will be effective for the Company beginning in 2015. The new guidance is not to be applied to a component that is classified as held for sale before the effective date of the guidance.

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***NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)***

**Note P Business Segments**

| (Millions of dollars) | Total Assets at June 30, 2014 | Three Months Ended June 30, 2014 External Revenues | Three Months Ended June 30, 2014 Income (Loss) | Three Months Ended June 30, 2013[1] External Revenues | Three Months Ended June 30, 2013[1] Income (Loss) |
|---|---|---|---|---|---|
| Exploration and production[2] | | | | | |
| United States | $ 5,377.5 | 507.3 | 101.7 | 444.2 | 122.9 |
| Canada | 4,126.5 | 262.8 | 52.9 | 316.8 | 51.7 |
| Malaysia | 6,087.0 | 583.0 | 172.3 | 554.7 | 213.5 |
| Other | 135.4 | (0.2) | (126.1) | (0.4) | (97.9) |
| Total exploration and production | 15,726.4 | 1,352.9 | 200.8 | 1,315.3 | 290.2 |
| Corporate | 1,228.2 | (3.9) | (58.1) | 16.7 | (30.3) |
| Assets/revenue/income from continuing operations | 16,954.6 | 1,349.0 | 142.7 | 1,332.0 | 259.9 |
| Discontinued operations, net of tax | 919.3 | 0.0 | (13.3) | 0.0 | 142.7 |
| Total | $ 17,873.9 | 1,349.0 | 129.4 | 1,332.0 | 402.6 |

| (Millions of dollars) | Six Months Ended June 30, 2014 External Revenues | Six Months Ended June 30, 2014 Income (Loss) | Six Months Ended June 30, 2013[1] External Revenues | Six Months Ended June 30, 2013[1] Income (Loss) |
|---|---|---|---|---|
| Exploration and production[2] | | | | |
| United States | $ 992.8 | 204.8 | 853.1 | 216.7 |
| Canada | 560.5 | 120.5 | 577.6 | 65.0 |
| Malaysia | 1,075.8 | 334.6 | 1,114.7 | 418.7 |
| Other | (0.2) | (248.5) | 68.9 | (178.3) |
| Total exploration and production | 2,628.9 | 411.4 | 2,614.3 | 522.1 |
| Corporate | 6.5 | (99.4) | 8.6 | (79.5) |
| Revenue/income from continuing operations | 2,635.4 | 312.0 | 2,622.9 | 442.6 |
| Discontinued operations, net of tax | 0.0 | (27.3) | 0.0 | 320.6 |
| Total | $ 2,635.4 | 284.7 | 2,622.9 | 763.2 |

1 Reclassified to conform to current presentation.

2 Additional details about results of oil and gas operations are presented in the tables on pages 25 and 26.

Due to the shutdown of production operations in Republic of the Congo, the Company now includes the results of these operations in the Other exploration and production segment in the above table.

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***ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION***

**Results of Operations**

Murphy s income by operating business is presented below.

| | Income (Loss) | | | |
|---|---|---|---|---|
| | Three Months Ended June 30, | | Six Months Ended June 30, | |
| (Millions of dollars) | 2014 | 2013 | 2014 | 2013 |
| Exploration and production | $ 200.8 | 290.2 | 411.4 | 522.1 |
| Corporate and other | (58.1) | (30.3) | (99.4) | (79.5) |
| Income from continuing operations | 142.7 | 259.9 | 312.0 | 442.6 |
| Discontinued operations | (13.3) | 142.7 | (27.3) | 320.6 |
| Net income | $ 129.4 | 402.6 | 284.7 | 763.2 |

Murphy s net income in the second quarter of 2014 was $129.4 million ($0.72 per diluted share) compared to net income of $402.6 million ($2.12 per diluted share) in the second quarter of 2013. The 2014 second quarter included a loss from discontinued operations of $13.3 million ($0.07 per diluted share) primarily related to refining and marketing operations in the U.K., which are held for sale. Discontinued operations reflected a profit of $142.7 million ($0.75 per diluted share) in the second quarter 2013, including a $68.8 million gain on sale of U.K. oil and gas assets, plus earnings of $77.9 million from U.S. retail marketing operations that were spun off to shareholders on August 30, 2013. Income from continuing operations decreased from $259.9 million ($1.37 per diluted share) in the 2013 quarter to $142.7 million ($0.79 per diluted share) in 2014. In the 2014 second quarter, the Company s exploration and production continuing operations earned $200.8 million compared to $290.2 million in the 2013 quarter. Income in the 2014 quarter was unfavorably impacted compared to 2013 by higher costs for oil and gas extraction and exploration activities, partially offset by higher oil sales volumes. The corporate function had after-tax costs of $58.1 million in the 2014 second quarter compared to after-tax costs of $30.3 million in the 2013 period with the unfavorable variance in the current period mostly due to higher net interest expense and unfavorable effects of foreign currency exchange.

For the first six months of 2014, net income totaled $284.7 million ($1.57 per diluted share) compared to net income of $763.2 million ($4.00 per diluted share) for the same period in 2013. Earnings in the first six months of 2014 included a loss from discontinued operations of $27.3 million ($0.15 per diluted share) compared to a profit of $320.6 million ($1.68 per diluted share) in the 2013 period. Discontinued operations in the 2013 period included after-tax gains of $216.2 million from sale of U.K. oil and gas assets, plus earnings of $107.3 million from U.S. retail marketing operations spun off on August 30, 2013. Continuing operations earned $312.0 million ($1.72 per diluted share) in the first six months of 2014, down from $442.6 million ($2.32 per diluted share) in the 2013 period. In the first six months of 2014, the Company s exploration and production operations earned $411.4 million from continuing operations compared to $522.1 million in the same period of 2013. Earnings in 2014 were below the 2013 period primarily due to higher exploration and depreciation expenses. These variances were partially offset by a favorable impact from higher oil and North American natural gas sales prices. Corporate after-tax costs were $99.4 million in the 2014 period compared to after-tax costs of $79.5 million in the 2013 period as the current period had higher interest expense and an unfavorable variance for the effects of foreign currency exchange.

*Exploration and Production*

Results of exploration and production continuing operations are presented by geographic segment below.

| | Income (Loss) | | | |
|---|---|---|---|---|
| | Three Months Ended June 30, | | Six Months Ended June 30, | |
| (Millions of dollars) | 2014 | 2013 | 2014 | 2013 |
| Exploration and production | | | | |
| United States | $ 101.7 | 122.9 | 204.8 | 216.7 |

| | | | | |
|---|---|---|---|---|
| Canada | 52.9 | 51.7 | 120.5 | 65.0 |
| Malaysia | 172.3 | 213.5 | 334.6 | 418.7 |
| Other International | (126.1) | (97.9) | (248.5) | (178.3) |
| Total | $ 200.8 | 290.2 | 411.4 | 522.1 |

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*ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)*

**Results of Operations *(Contd.)***

*Exploration and Production (Contd.)*

*Second quarter 2014 vs. 2013*

United States exploration and production operations reported a profit of $101.7 million in the second quarter of 2014 compared to a profit of $122.9 million in the 2013 quarter. Earnings were $21.2 million lower in the 2014 quarter compared to the same period in 2013 as higher oil and natural gas sales volumes were more than offset by the impacts of derivative contracts and higher expenses. Revenue in the U.S. rose $63.1 million in the second quarter 2014 primarily due to higher oil and natural gas volumes produced and sold in the Eagle Ford Shale in South Texas, where a significant development drilling program is ongoing with eight active land rigs. Revenue in 2014 was unfavorably affected by $16.4 million for payments under matured West Texas Intermediate (WTI) oil derivative contracts, and by $18.1 million to recognize the fair value at June 30, 2014 of open crude oil sales derivative contracts covering certain future 2014 production in the Eagle Ford Shale. The WTI contracts that matured during the second quarter reduced the realized sales price for Eagle Ford Shale crude oil by $4.21 per barrel. Although U.S. oil prices in the 2014 quarter were below 2013, principally due to the crude oil contracts, natural gas prices were stronger compared to a year earlier. Lease operating, production tax and depreciation expenses increased $16.7 million, $8.3 million and $50.9 million, respectively, in 2014 compared to 2013 due to both higher production in the Eagle Ford Shale area and start up of the Dalmatian field in the Gulf of Mexico. Exploration expense was up $12.4 million in 2014 primarily related to higher amortization expense associated with certain Eagle Ford Shale leases that were not extended. Selling and general expenses in the 2014 period increased $5.1 million from the prior year primarily due to higher staffing costs.

Operations in Canada had earnings of $52.9 million in the second quarter 2014 compared to earnings of $51.7 million in the 2013 quarter. Canadian earnings were $1.2 million higher in the 2014 quarter as stronger profits for conventional oil and natural gas operations were offset by weaker profits for synthetic oil operations. Conventional operations improved in 2014 mostly due to no repeat of a 2013 period impairment charge of $21.6 million to write down wells performing below expectations in the Kainai area of Southern Alberta, plus higher oil and natural gas sales prices. Sales prices for crude oil and natural gas increased in all Canadian producing areas in the second quarter of 2014 compared to the prior year. Oil production declined in Canada in the 2014 period compared to 2013 primarily due to lower volumes at Syncrude, where more downtime for maintenance was experienced in the current quarter, and lower volumes of heavy oil produced in the Seal area of Alberta due to well decline. Natural gas sales volumes decreased in 2014 due to lower production in the Tupper area of Western Canada. Production and depreciation expenses for conventional oil and natural gas operations in Canada were lower in 2014 by $11.8 million and $23.5 million, respectively, due primarily to less heavy oil and natural gas production volumes in 2014. Synthetic oil operations incurred higher production expenses of $3.0 million in 2014, despite having lower oil production, due to added equipment repair costs in the latter period.

Operations in Malaysia reported earnings of $172.3 million in the 2014 quarter compared to earnings of $213.5 million during the same period in 2013. Earnings were down $41.2 million in 2014 in Malaysia primarily from a combination of lower sales volumes from the Kikeh oil field offshore Sabah and lower realized sales prices for oil and natural gas produced offshore Sarawak. These impacts were partially offset by higher crude oil production and sales volumes for new oil fields offshore Sarawak and at Siakap North offshore Sabah. The 2014 quarter included a significantly larger impact from contractually required revenue sharing with the local government. This unfavorable impact between quarters primarily affected oil and natural gas prices at fields offshore Sarawak. Lease operating expense increased in the 2014 period by $34.8 million primarily due to a favorable adjustment in 2013 associated with finalization of gas liquids processing fees retroactive to the beginning of this production, plus higher costs during 2014 associated with oil production at new fields offshore Sarawak and at Siakap North. Depreciation expense was $52.7 million more in 2014 compared to the 2013 quarter primarily due to the current quarter including a higher cost mix associated with new oil production offshore Sarawak and at the Siakap North field offshore Sabah. Selling and general expense rose $4.9 million in 2014 due to higher staffing costs being only partially recovered through joint operating agreements with partners.

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*ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)*

**Results of Operations *(Contd.)***

*Exploration and Production (Contd.)*

*Second quarter 2014 vs. 2013 (Contd.)*

Other international operations reported a loss of $126.1 million in the second quarter of 2014 compared to a loss of $97.9 million in the 2013 quarter. The $28.2 million increase in costs in the current quarter was primarily related to higher seismic costs associated with prospects in Namibia, Vietnam, Australia and at areas along the Atlantic Margin. Additionally, an expense was incurred in connection with relinquishing the exploration license on the South Barito block onshore Indonesia.

Total hydrocarbon production averaged 210,191 barrels of oil equivalent per day in the 2014 second quarter, up from the 207,401 barrel equivalents per day produced in the 2013 quarter. Average crude oil and condensate production was 130,750 barrels per day in the second quarter of 2014 compared to 131,758 barrels per day in the second quarter of 2013. Crude oil production increased in the Eagle Ford Shale area of South Texas in 2014 due to a significant ongoing development drilling and completion program. Heavy oil production from the Seal area in Western Canada was lower in 2014 due to field declines. Oil production at Syncrude was lower in 2014 due to downtime associated with repairs of two coking units during a portion of the current quarter. Oil production offshore Eastern Canada was lower during 2014 primarily due to more downtime for equipment repairs at the Terra Nova field. On a worldwide basis, the Company s crude oil and condensate prices averaged $93.56 per barrel in the second quarter 2014 compared to $92.80 in the 2013 period. The average sales prices for U.S. natural gas liquids was $29.32 per barrel in the 2014 quarter compared to $28.63 per barrel in 2013. Natural gas sales volumes averaged 425 million cubic feet per day in the second quarter 2014, down from 431 million cubic feet per day in the 2013 quarter. The decrease in natural gas sales volumes in 2014 was primarily attributable to lower gas volumes produced in the Tupper area in Western Canada as development drilling activities have been below spending levels needed to fully offset normal well decline during recent periods of relatively low sales prices in the Canadian market. Additionally, natural gas sales volumes from offshore Sarawak fields in 2014 were less than 2013 due to both performance issues at the third party receiving facility and a lower entitlement allocation to the Company under the production sharing contract. Natural gas sales volumes increased in the U.S. in 2014 due to ongoing development drilling in the Eagle Ford Shale and start up of the Dalmatian field in the Gulf of Mexico. North American natural gas sales prices averaged $4.03 per thousand cubic feet (MCF) in the 2014 quarter compared to $3.63 per MCF in the same quarter of 2013. The average realized price for natural gas produced in 2014 at fields offshore Sarawak was $5.32 per MCF, compared to a price of $6.98 per MCF in the 2013 quarter. The Sarawak price declined in 2014 primarily due to higher revenue sharing with the government.

*Six months 2014 vs. 2013*

U.S. E&P operations had income of $204.8 million for the six months ended June 30, 2014 compared to income of $216.7 million in the 2013 period. The 2014 income reduction of $11.9 million was primarily caused by higher exploration expense, which increased $21.1 million in the current year due to higher costs for an unsuccessful exploration well that spud in late 2013 in the Gulf of Mexico, and higher amortization expense associated with certain Eagle Ford Shale leases that were not extended. The 2014 period benefited from higher crude oil production volumes, primarily at the Eagle Ford Shale area. The 2014 period also had higher average realized natural gas sales prices compared to 2013, but realized oil prices were lower year over year. The oil price decline in 2014 was partially caused by net payments of $17.9 million under matured WTI oil contracts. These contracts reduced the Eagle Ford Shale realized oil price by $2.38 per barrel of crude oil produced and sold. In addition, revenue in the U.S. was reduced by $36.5 million to recognize the fair value of remaining open WTI crude oil contracts, which cover a portion of Eagle Ford Shale oil production for the last six months of 2014. Lease operating, production tax and depreciation expenses were higher by $15.7 million, $19.3 million and $88.6 million, respectively, in 2014 than 2013 mostly due to production growth in the Eagle Ford Shale. Selling and general expenses rose by $12.0 million in 2014 compared to 2013, primarily driven by increased staffing and support costs.

Canadian operations had income of $120.5 million in the first half of 2014 compared to income of $65.0 million a year ago. Operating results for conventional operations improved $74.2 million during the first half of 2014, but this was somewhat offset by lower earnings of $18.7 million for synthetic oil operations. Sales revenue within conventional operations for 2014 was about even with the prior year as better heavy oil and natural gas sales prices mostly offset lower heavy oil and natural gas sales volumes. Lease operating and depreciation expenses for conventional operations were lower by $13.5 million and $37.2 million, respectively, in 2014 mostly related to lower sales volumes

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*ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)*

**Results of Operations *(Contd.)***

*Exploration and Production (Contd.)*

*Six months 2014 vs. 2013 (Contd.)*

in the current year. Exploration expenses in 2014 were $30.4 million less than 2013 primarily due to prior-year dry hole costs at Rainbow in the Muskwa Shale area of Northern Alberta. Impairment expense of $21.6 million in 2013 related to a write down of wells performing below expectations in the Kainai area of Southern Alberta. Synthetic oil operations earnings declined in 2014 primarily due to lower production volumes caused by two coking units being idled for repairs during a portion of the second quarter 2014. Additionally, synthetic oil operations incurred higher lease operating costs of $12.0 million in the current year due to a combination of higher natural gas costs used in production operations and more equipment repair costs.

Malaysia operations earned $334.6 million in the first half of 2014 compared to earnings of $418.7 million in the 2013 period. Earnings were down $84.1 million in 2014 primarily due to lower crude oil sales volumes at the Kikeh field, offshore Sabah, lower realized sales prices for Sarawak natural gas production, and higher extraction costs. Higher crude oil volumes sold at new fields offshore Sarawak partially offset these unfavorable variances. The 2014 period experienced higher revenue sharing with the local government under the existing production sharing contracts. Lease operating expense in 2014 was higher than in 2013 by $29.5 million primarily due to a benefit in the prior year for a retroactive processing fee adjustment related to gas liquids processing. Depreciation expense was up $61.8 million in 2014 primarily due to higher average per-unit depreciation rates for new Malaysian production volumes at offshore Sarawak fields and at the Siakap North field offshore Sabah. Selling and general expenses rose $7.8 million in 2014 compared to the prior year due to higher staffing costs.

Other international operations reported a loss of $248.5 million in the first six months of 2014 compared to a loss of $178.3 million in the 2013 period. The 2014 period included higher dry hole costs of $71.3 million, which were primarily associated with unsuccessful wildcat drilling offshore Cameroon. The current period included higher geological and geophysical expense of $7.3 million, principally for seismic data acquired in Namibia. Other exploration expenses were $9.0 million higher in the current year, mostly attributable to an expense incurred in connection with relinquishing the exploration license on the South Barito block onshore Indonesia. Selling and general expenses increased $7.4 million in 2014 due to higher staffing costs to support foreign exploration activities. The first half of 2013 included oil revenue and associated production expense at the Azurite field, offshore Republic of the Congo. The field ceased production in late 2013.

Total worldwide production averaged 207,329 barrels of oil equivalent per day during the six months ended June 30, 2014, an increase from 204,653 barrels of oil equivalent produced in the same period in 2013. Crude oil, condensate and gas liquids production in the first half of 2014 averaged 131,159 barrels per day compared to 128,910 barrels per day a year ago. Higher oil production in the Eagle Ford Shale, where additional wells have been brought on production as part of a significant ongoing development drilling and completion program, more than offset oil production declines in certain other areas. Heavy oil production in Canada declined in 2014 in the Seal area of Western Canada. Synthetic oil production in Canada also was lower in 2014 due to more downtime for equipment repairs in the current period. Oil production offshore Eastern Canada was lower in 2014 due to less production at both the Hibernia and Terra Nova fields. Lower oil production in 2014 in Malaysia was primarily attributable to less net oil volumes produced at the Kikeh field, but partially offset by higher volumes at new oil fields offshore Sarawak and at Siakap North, offshore Sabah. Production at the Kikeh field was unfavorably affected by downtime for hook-up of the Siakap North field and a rig fire in early 2014. Full field start-up at the non-operated Kakap field offshore Sabah is scheduled for the second half of 2014. For the first six months of 2014, the Company s sales price for crude oil and condensate averaged $95.57 per barrel, up from $94.24 per barrel in 2013. The sales price for U.S. natural gas liquids averaged $31.59 per barrel in 2014. Natural gas sales volumes decreased from 441 million cubic feet per day in 2013 to 413 million cubic feet per day in 2014, with the reduction due to lower gas production volumes in the Tupper area in British Columbia, where drilling activity has been curtailed due to weak North American natural gas sales prices in recent years. Natural gas sales volumes in 2014 in the U.S. increased due to drilling in the Eagle Ford Shale area and start-up of the Dalmatian field in the Gulf of Mexico. The average sales price for North American natural gas in the first six months of 2014 was $4.08 per MCF, up from $3.36 per MCF realized in 2013. Natural gas production at fields offshore Sarawak was sold at an average realized price of $5.87 per MCF in 2014 compared to $7.03 per MCF in 2013. The Sarawak gas price was lower in 2014 primarily due to higher levels of revenue sharing with the local government during the current year.

Additional details about results of oil and gas operations are presented in the tables on pages 25 and 26.

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*ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)*

**Results of Operations (Contd.)**

*Exploration and Production* (Contd.)

Selected operating statistics for the three-month and six-month periods ended June 30, 2014 and 2013 follow.

| | Three Months Ended June 30, 2014 | Three Months Ended June 30, 2013 | Six Months Ended June 30, 2014 | Six Months Ended June 30, 2013 |
|---|---|---|---|---|
| Net crude oil and condensate produced barrels per day | 130,750 | 131,758 | 131,159 | 128,910 |
| Continuing operations | 130,750 | 130,791 | 131,159 | 127,604 |
| United States Eagle Ford Shale | 42,382 | 34,261 | 41,573 | 29,710 |
| Gulf of Mexico and other | 11,561 | 10,631 | 11,605 | 12,658 |
| Canada light | 48 | 162 | 38 | 195 |
| heavy | 7,533 | 10,920 | 7,763 | 9,726 |
| offshore | 7,991 | 9,641 | 8,416 | 9,443 |
| synthetic | 9,576 | 13,000 | 11,624 | 12,710 |
| Malaysia Sarawak | 17,876 | 6,674 | 18,528 | 5,983 |
| Block K | 33,783 | 44,268 | 31,612 | 45,855 |
| Republic of the Congo | | 1,234 | | 1,324 |
| Discontinued operations United Kingdom | | 967 | | 1,306 |
| Net crude oil and condensate sold barrels per day | 137,852 | 133,897 | 132,639 | 132,538 |
| Continuing operations | 137,852 | 132,942 | 132,639 | 131,285 |
| United States Eagle Ford Shale | 42,382 | 34,261 | 41,573 | 29,710 |
| Gulf of Mexico and other | 11,561 | 10,631 | 11,605 | 12,658 |
| Canada light | 48 | 162 | 38 | 195 |
| heavy | 7,533 | 10,920 | 7,763 | 9,726 |
| offshore | 8,887 | 10,145 | 9,374 | 9,050 |
| synthetic | 9,576 | 13,000 | 11,624 | 12,710 |
| Malaysia Sarawak | 19,617 | 6,517 | 20,081 | 6,644 |
| Block K | 38,248 | 47,306 | 30,581 | 47,190 |
| Republic of the Congo | | | | 3,402 |
| Discontinued operations United Kingdom | | 955 | | 1,253 |
| Net natural gas liquids produced barrels per day[1] | 8,583 | 3,759 | 7,389 | 2,316 |
| United States Eagle Ford Shale | 5,383 | 2,099 | 4,844 | 1,173 |
| Gulf of Mexico and other | 2,399 | 1,033 | 1,747 | 524 |
| Canada | 24 | | 23 | |
| Malaysia Sarawak | 777 | 627 | 775 | 619 |
| Net natural gas liquids sold barrels per day[1] | 7,886 | 3,209 | 7,174 | 1,770 |
| United States Eagle Ford Shale | 5,383 | 2,099 | 4,844 | 1,173 |
| Gulf of Mexico and other | 2,399 | 1,033 | 1,747 | 524 |
| Canada | 24 | | 23 | |
| Malaysia Sarawak | 80 | 77 | 560 | 73 |
| Net natural gas sold thousands of cubic feet per day | 425,148 | 431,302 | 412,686 | 440,562 |
| Continuing operations | 425,148 | 430,913 | 412,686 | 438,919 |
| United States Eagle Ford Shale | 30,295 | 19,906 | 28,895 | 20,535 |
| Gulf of Mexico and other | 51,311 | 31,871 | 42,543 | 35,074 |
| Canada | 134,828 | 169,166 | 141,360 | 180,420 |
| Malaysia Sarawak | 161,343 | 167,447 | 161,501 | 158,316 |

| | | | | |
|---|---|---|---|---|
| Block K | 47,371 | 42,523 | 38,387 | 44,574 |
| Discontinued operations United Kingdom | | 389 | | 1,643 |
| Total net hydrocarbons produced equivalent barrels per day[2] | 210,191 | 207,401 | 207,329 | 204,653 |
| Total net hydrocarbons sold equivalent barrels per day[2] | 216,596 | 208,990 | 208,594 | 207,735 |

[1] U.S. and Canada NGLs were included in the wet natural gas stream during early 2013.

[2] Natural gas converted on an energy equivalent basis of 6:1.

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*ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)*

**Results of Operations** ***(Contd.)***

| Exploration and Production (Contd.) | Three Months Ended June 30, 2014 | Three Months Ended June 30, 2013 | Six Months Ended June 30, 2014 | Six Months Ended June 30, 2013 |
|---|---|---|---|---|
| Weighted average sales prices | | | | |
| Crude oil and condensate dollars per barrel | | | | |
| United States Eagle Ford Shale | $ 95.88 | 101.38 | 96.65 | 103.07 |
| Gulf of Mexico and other | 101.88 | 103.92 | 101.06 | 106.55 |
| Canada (1) light | 97.69 | 85.92 | 96.31 | 83.64 |
| heavy | 61.34 | 49.90 | 56.21 | 39.87 |
| offshore | 109.42 | 102.47 | 108.42 | 106.39 |
| synthetic | 102.77 | 98.64 | 98.42 | 96.53 |
| Malaysia Sarawak (2) | 88.17 | 94.23 | 95.32 | 98.45 |
| Block K (2) | 91.61 | 89.97 | 97.16 | 91.35 |
| Republic of the Congo (2) | | | | 112.89 |
| Discontinued operations United Kingdom | | 101.40 | | 108.58 |
| Natural gas liquids dollars per barrel | | | | |
| United States Eagle Ford Shale | $ 27.70 | 27.06 | 30.36 | 27.06 |
| Gulf of Mexico and other | 32.69 | 31.69 | 34.67 | 31.69 |
| Canada (1) | 96.63 | | 82.65 | |
| Malaysia Sarawak (2) | 78.46 | 101.84 | 86.60 | 104.10 |
| Natural gas dollars per thousand cubic feet | | | | |
| United States Eagle Ford Shale | $ 4.30 | 4.18 | 4.43 | 3.92 |
| Gulf of Mexico and other | 4.46 | 4.52 | 4.68 | 3.89 |
| Canada (1) | 3.80 | 3.40 | 3.83 | 3.19 |
| Malaysia Sarawak (2) | 5.32 | 6.98 | 5.87 | 7.03 |
| Block K | 0.23 | 0.24 | 0.24 | 0.24 |
| Discontinued operations United Kingdom | | 12.47 | | 12.32 |

(1) U.S. dollar equivalent.
(2) Prices are net of payments under the terms of the respective production sharing contracts.

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*ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)*

**Results of Operations *(Contd.)***

*Exploration and Production (Contd.)*

***OIL AND GAS OPERATING RESULTS THREE MONTHS ENDED JUNE 30, 2014 AND 2013***

| | | Canada | | | | |
|---|---|---|---|---|---|---|
| (Millions of dollars) | United States | Conven-tional | Syn-thetic | Malaysia | Other | Total |
| **Three Months Ended June 30, 2014** | | | | | | |
| Oil and gas sales and other operating revenues | $ 507.3 | 173.7 | 89.1 | 583.0 | (0.2) | 1,352.9 |
| Lease operating expenses | 81.6 | 39.7 | 60.8 | 103.7 | | 285.8 |
| Severance and ad valorem taxes | 26.5 | 1.2 | 1.2 | | | 28.9 |
| Depreciation, depletion and amortization | 188.6 | 62.4 | 12.3 | 192.4 | 1.2 | 456.9 |
| Accretion of asset retirement obligations | 4.3 | 1.6 | 2.3 | 4.2 | | 12.4 |
| Exploration expenses | | | | | | |
| Dry holes | 0.7 | | | | 39.2 | 39.9 |
| Geological and geophysical | 1.3 | 0.1 | | | 37.9 | 39.3 |
| Other | 2.4 | 0.2 | | | 28.1 | 30.7 |
| | 4.4 | 0.3 | | | 105.2 | 109.9 |
| Undeveloped lease amortization | 18.7 | 5.0 | | | 1.2 | 24.9 |
| Total exploration expenses | 23.1 | 5.3 | | | 106.4 | 134.8 |
| Selling and general expenses | 24.6 | 7.2 | 0.2 | 5.0 | 19.0 | 56.0 |
| Other expenses | 0.5 | | | | (0.7) | (0.2) |
| Results of operations before taxes | 158.1 | 56.3 | 12.3 | 277.7 | (126.1) | 378.3 |
| Income tax provisions | 56.4 | 12.5 | 3.2 | 105.4 | | 177.5 |
| Results of operations (excluding corporate overhead and interest) | $ 101.7 | 43.8 | 9.1 | 172.3 | (126.1) | 200.8 |
| **Three Months Ended June 30, 2013** | | | | | | |
| Oil and gas sales and other operating revenues | $ 444.2 | 200.1 | 116.7 | 554.7 | (0.4) | 1,315.3 |
| Lease operating expenses | 64.9 | 51.5 | 57.8 | 68.9 | 8.7 | 251.8 |
| Severance and ad valorem taxes | 18.2 | 0.9 | 1.2 | | | 20.3 |
| Depreciation, depletion and amortization | 137.7 | 85.9 | 14.0 | 139.7 | 1.4 | 378.7 |
| Accretion of asset retirement obligations | 3.3 | 1.5 | 2.5 | 3.4 | 1.3 | 12.0 |
| Impairment of properties | | 21.6 | | | | 21.6 |
| Exploration expenses | | | | | | |
| Dry holes | | (0.1) | | 0.8 | 39.6 | 40.3 |
| Geological and geophysical | 0.4 | (0.7) | | 0.8 | 19.7 | 20.2 |
| Other | 3.1 | 0.3 | | | 8.2 | 11.6 |
| | 3.5 | (0.5) | | 1.6 | 67.5 | 72.1 |
| Undeveloped lease amortization | 7.2 | 5.3 | | | 4.2 | 16.7 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total exploration expenses | 10.7 | 4.8 | | 1.6 | 71.7 | 88.8 |
| Selling and general expenses | 19.5 | 4.9 | 0.2 | 0.1 | 14.5 | 39.2 |
| Results of operations before taxes | 189.9 | 29.0 | 41.0 | 341.0 | (98.0) | 502.9 |
| Income tax provisions (benefits) | 67.0 | 7.6 | 10.7 | 127.5 | (0.1) | 212.7 |
| Results of operations (excluding corporate overhead and interest) | $ 122.9 | 21.4 | 30.3 | 213.5 | (97.9) | 290.2 |

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***ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)***

**Results of Operations *(Contd.)***

*Exploration and Production (Contd.)*

***OIL AND GAS OPERATING RESULTS SIX MONTHS ENDED JUNE 30, 2014 AND 2013***

| | | Canada | | | | |
|---|---|---|---|---|---|---|
| (Millions of dollars) | United States | Conven-tional | Syn-thetic | Malaysia | Other | Total |
| **Six Months Ended June 30, 2014** | | | | | | |
| Oil and gas sales and other operating revenues | $ 992.8 | 353.9 | 206.6 | 1,075.8 | (0.2) | 2,628.9 |
| Lease operating expenses | 158.1 | 80.5 | 124.5 | 185.0 | | 548.1 |
| Severance and ad valorem taxes | 50.4 | 2.5 | 2.3 | | | 55.2 |
| Depreciation, depletion and amortization | 356.7 | 130.2 | 26.4 | 335.4 | 2.3 | 851.0 |
| Accretion of asset retirement obligations | 8.4 | 3.1 | 4.6 | 8.3 | | 24.4 |
| Exploration expenses | | | | | | |
| Dry holes | 7.5 | | | | 120.3 | 127.8 |
| Geological and geophysical | 15.8 | 0.2 | | | 53.4 | 69.4 |
| Other | 4.1 | 0.5 | | | 33.7 | 38.3 |
| | 27.4 | 0.7 | | | 207.4 | 235.5 |
| Undeveloped lease amortization | 25.4 | 9.9 | | | 2.5 | 37.8 |
| Total exploration expenses | 52.8 | 10.6 | | | 209.9 | 273.3 |
| Selling and general expenses | 47.6 | 15.1 | 0.5 | 8.4 | 36.1 | 107.7 |
| Other expenses | 0.5 | 0.1 | | | | 0.6 |
| Results of operations before taxes | 318.3 | 111.8 | 48.3 | 538.7 | (248.5) | 768.6 |
| Income tax provisions | 113.5 | 27.0 | 12.6 | 204.1 | | 357.2 |
| Results of operations (excluding corporate overhead and interest) | $ 204.8 | 84.8 | 35.7 | 334.6 | (248.5) | 411.4 |
| **Six Months Ended June 30, 2013** | | | | | | |
| Oil and gas sales and other operating revenues | $ 853.1 | 355.5 | 222.1 | 1,114.7 | 68.9 | 2,614.3 |
| Lease operating expenses | 142.4 | 94.0 | 112.5 | 155.5 | 84.6 | 589.0 |
| Severance and ad valorem taxes | 31.1 | 1.8 | 2.5 | | | 35.4 |
| Depreciation, depletion and amortization | 268.1 | 167.4 | 27.7 | 273.6 | 2.6 | 739.4 |
| Accretion of asset retirement obligations | 6.6 | 3.0 | 5.2 | 6.7 | 2.4 | 23.9 |
| Impairment of properties | | 21.6 | | | | 21.6 |
| Exploration expenses | | | | | | |
| Dry holes | 0.7 | 30.4 | | 1.2 | 49.0 | 81.3 |
| Geological and geophysical | 13.1 | (0.6) | | 1.1 | 46.1 | 59.7 |
| Other | 4.6 | 0.6 | | | 19.0 | 24.2 |
| | 18.4 | 30.4 | | 2.3 | 114.1 | 165.2 |
| Undeveloped lease amortization | 13.3 | 10.6 | | | 8.2 | 32.1 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total exploration expenses | 31.7 | 41.0 | | 2.3 | 122.3 | 197.3 |
| Selling and general expenses | 35.6 | 11.3 | 0.4 | 0.6 | 28.7 | 76.6 |
| Results of operations before taxes | 337.6 | 15.4 | 73.8 | 676.0 | (171.7) | 931.1 |
| Income tax provisions | 120.9 | 4.8 | 19.4 | 257.3 | 6.6 | 409.0 |
| Results of operations (excluding corporate overhead and interest) | $ 216.7 | 10.6 | 54.4 | 418.7 | (178.3) | 522.1 |

*ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)*

**Results of Operations** ***(Contd.)***

*Corporate*

Corporate activities, which include interest income and expense, foreign exchange effects, and corporate overhead not allocated to operating functions, had net costs of $58.1 million in the 2014 second quarter compared to net costs of $30.3 million in the 2013 second quarter. Net costs in the current year were $27.8 million above the prior year due to unfavorable impacts from foreign currency exchange and higher net interest expense. Net after-tax losses of $7.2 million were incurred in 2014 on transactions denominated in foreign currencies, while the 2013 quarter had net after-tax gains of $16.2 million. The increase in net interest expense was mostly associated with higher borrowing levels in the current year, coupled with lower financing costs being allocated to development projects in 2014.

For the first six months of 2014, corporate activities reflected net costs of $99.4 million compared to net costs of $79.5 million a year ago. Six-month corporate costs in 2014 were unfavorable to 2013 by $19.9 million mostly related to higher interest expense and unfavorable foreign exchange impacts. Net interest expense was higher in 2014 compared to 2013 primarily due to larger average borrowings and lower levels of finance costs allocated to development projects in the current year. Total after-tax losses associated with foreign currency transactions were $4.1 million in the 2014 period compared to after-tax gains of $12.2 million in the first six months of 2013.

*Discontinued Operations*

The Company has presented a number of businesses as discontinued operations in its consolidated financial statements. These businesses included:

- U.K. refining and marketing company held for sale at June 30, 2014. The Company ceased processing crude oil throughputs at the Milford Haven, Wales refinery in May 2014 due to weak operating margins. Weak refining margins, plus fewer crude oil barrels processed to cover ongoing operating costs, led to larger losses for this business in the 2014 quarter compared to the prior year. On July 31, 2014 the Company signed an agreement to sell the Milford Haven, Wales refinery and terminal assets. Pending regulatory approval and subject to other material conditions, this transaction is scheduled to be completed by October 31, 2014. Additionally, a separate transaction for the sale of the Company s U.K. retail marketing business is at an advanced stage.

- U.S. retail marketing company spun-off to shareholders on August 30, 2013. Results of operations for this business were included in the Company s 2013 financial statements through the spin-off date.

- U.K. oil and gas assets sold through a series of transactions in the first half of 2013. The Company s 2013 financial statements included the results of operations through the respective dates the assets were sold, plus the cumulative gain realized upon sale. The three-month and six-month periods ended June 30, 2013 included after-tax gains of $68.8 million and $216.2 million, respectively, from the sale of these properties.

The after-tax results of these operations for the three-month and six-month periods ended June 30, 2014 and 2013 are reflected in the following table.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (Millions of dollars) | 2014 | 2013 | 2014 | 2013 |
| U.K. refining and marketing | $ (13.2) | (5.7) | (27.0) | (9.8) |

| | | | | |
|---|---|---|---|---|
| U.S. refining and marketing | | 77.9 | | 107.3 |
| U.K. exploration and production | (0.1) | 70.5 | (0.3) | 223.1 |
| Income (loss) from discontinued operations | $ (13.3) | 142.7 | (27.3) | 320.6 |

*ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)*

**Results of Operations *(Contd.)***

*Discontinued Operations (Contd.)*

Selected operating statistics for the U.K. refining and marketing operations for the three-month and six-month periods ended June 30, 2014 and 2013 follow.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| U.K. refining and marketing unit margins per barrel of petroleum products sold | $ (1.72) | (0.27) | (1.15) | (0.16) |
| U.K. petroleum products sold barrels per day | 72,217 | 137,517 | 99,783 | 127,950 |
| Gasoline | 25,090 | 49,103 | 35,449 | 46,819 |
| Kerosine | 6,732 | 15,370 | 12,409 | 15,238 |
| Diesel and home heating oils | 27,612 | 51,103 | 34,817 | 46,592 |
| Residuals | 7,227 | 16,869 | 8,723 | 14,795 |
| LPG and other | 5,556 | 5,072 | 8,385 | 4,506 |
| U.K. refinery inputs barrels per day | 52,321 | 133,220 | 85,752 | 124,542 |
| Milford Haven, Wales crude oil | 50,279 | 130,324 | 82,741 | 121,417 |
| other feedstocks | 2,042 | 2,896 | 3,011 | 3,125 |
| U.K. refinery yields barrels per day | 52,321 | 133,220 | 85,752 | 124,542 |
| Gasoline | 22,381 | 47,292 | 31,931 | 43,875 |
| Kerosine | 7,201 | 17,058 | 11,985 | 16,266 |
| Diesel and home heating oils | 18,427 | 48,626 | 28,239 | 44,637 |
| Residuals | 4,837 | 15,309 | 8,040 | 13,731 |
| LPG and other | (2,761) | 1,757 | 3,137 | 2,952 |
| Fuel and loss | 2,236 | 3,178 | 2,420 | 3,081 |

**Financial Condition**

Net cash provided by operating activities was $1,459.7 million for the first six months of 2014 compared to $1,669.0 million during the same period in 2013. Excluding discontinued operations, cash flow from continuing operations increased from $1,269.0 million in the first six months of 2013 to $1,455.2 million in the same 2014 period. Changes in operating working capital other than cash and cash equivalents from continuing operations generated cash of $48.8 million during the first six months of 2014, but these working capital changes required cash of $131.8 million in 2013. Other significant sources of cash included $320.3 million in the 2014 period and $358.9 million in 2013 from maturity of Canadian government securities that had maturity dates greater than 90 days at acquisition. The sale of all U.K. oil and gas properties generated cash proceeds of $282.2 million during 2013. The Company borrowed $850.0 million and $462.0 million in the six-month periods of 2014 and 2013, respectively, to fund capital development activities and repurchase Company stock.

The most significant use of cash in both years was for property additions and dry holes for continuing operations, which including amounts expensed, were $1,840.5 million and $1,853.9 million in the six-month periods ended June 30, 2014 and 2013, respectively. Total cash dividends to shareholders amounted to $112.1 million in 2014 and $119.4 million in 2013. The Company paid quarterly dividends on outstanding Common stock of $0.3125 per share in each of the first two quarters of 2014 and 2013. The Company expended $375.0 million to acquire 5,991,489 shares of Common stock through share repurchases during the first six months of 2014. In the first six months of 2013, the Company spent $250.0 million to repurchase Common shares. Also, the purchase of Canadian government securities with maturity dates greater than 90 days at acquisition used cash of $372.9 million in the 2014 period and $373.2 million in the 2013 period.

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*ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)*

**Financial Condition** ***(Contd.)***

Total accrual basis capital expenditures for continuing operations follow.

| (Millions of dollars) | Six Months Ended June 30, 2014 | 2013 |
|---|---|---|
| Capital Expenditures | | |
| Exploration and production | $ 1,853.1 | 1,960.5 |
| Corporate | 3.2 | 6.6 |
| Total capital expenditures, including discontinued operations | $ 1,856.3 | 1,967.1 |

The reduction in capital expenditures in the exploration and production business in 2014 was primarily attributable to lower levels of development spend in Malaysia, but this was somewhat offset by more drilling and development activities in the Eagle Ford Shale area and higher spend on lease acquisitions in the Gulf of Mexico in the current year. Capital expenditures exclude production equipment leased at the Kakap field, offshore Malaysia, during 2013.

A reconciliation of property additions and dry hole costs in the Consolidated Statements of Cash Flows to total capital expenditures for continuing operations follows.

| (Millions of dollars) | Six Months Ended June 30, 2014 | 2013 |
|---|---|---|
| Property additions and dry hole costs per cash flow statements | $ 1,840.5 | 1,853.9 |
| Geophysical and other exploration expenses | 107.7 | 83.9 |
| Capital expenditure accrual changes | (91.9) | 29.3 |
| Total capital expenditures | $ 1,856.3 | 1,967.1 |

Working capital (total current assets less total current liabilities) at June 30, 2014 was $382.4 million, $97.8 million more than December 31, 2013, with the increase primarily due to lower accounts payable owed on capital projects at June 30, 2014.

At June 30, 2014, long-term debt of $3,786.5 million had increased by $849.9 million compared to December 31, 2013. A summary of capital employed at June 30, 2014 and December 31, 2013 follows.

| | June 30, 2014 | | Dec. 31, 2013 | |
|---|---|---|---|---|
| (Millions of dollars) | Amount | % | Amount | % |
| Capital employed | | | | |
| Long-term debt | $ 3,786.5 | 31.1% | $ 2,936.6 | 25.5% |
| Stockholders equity | 8,398.9 | 68.9 | 8,595.7 | 74.5 |
| Total capital employed | $ 12,185.4 | 100.0% | $ 11,532.3 | 100.0% |

The Company s ratio of earnings to fixed charges was 7.5 to 1 for the six-month period ended June 30, 2014.

Cash and invested cash are maintained in several operating locations outside the United States. At June 30, 2014, cash, cash equivalents and cash temporarily invested in Canadian government securities held outside the U.S. included U.S. dollar equivalents of approximately $500 million in Canada, $509 million in Malaysia and $242 million in the United Kingdom. In certain cases, the Company could incur taxes or other costs should these cash balances be repatriated to the U.S. in future periods. This could occur due to withholding taxes and/or potential additional U.S. tax burden when less than the U.S. Federal tax rate of 35% has been paid for cash taxes in foreign locations. A lower cash tax rate is often paid in foreign countries in the early years of operations when accelerated tax deductions exist to spur oil and gas investments; cash tax rates are generally higher in later years after accelerated tax deductions in early years are exhausted. Canada collects a 5% withholding tax on any cash repatriated to the United States.

*ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)*

**Accounting and Other Matters**

The United States Congress passed the Dodd-Frank Act (the Act) in 2010. As mandated by the Act, the U.S. Securities and Exchange Commission (SEC) issued rules regarding annual disclosures for purchases of conflict minerals and payments made to the U.S. Federal and all foreign governments by extractive industries, including oil and gas companies. Conflict minerals are defined as tin, tantalum, tungsten and gold which originate from the Democratic Republic of Congo or adjoining countries. For companies to whom the rule applies, the first annual report for conflict minerals was required to be filed no later than June 2, 2014 for the calendar year of 2013. Based on its assessment, the Company has determined that the rule does not currently apply to it and, therefore, it did not file an annual conflict minerals report for 2013.

On July 2, 2013, the United States District Court for the District of Columbia vacated the SEC s rules regarding reporting of payments made to the U.S. Federal and foreign governments. The D.C. Court found that the SEC misread the Act to mandate public disclosure of reports and that the denial of exemptions in the case of countries that prohibit public disclosures was improper. The Court remanded the matter to the SEC, which has indicated that it will restart the rulemaking process. The SEC has targeted the first quarter of 2015 for issuance of new rules on this matter. The Company cannot predict how the SEC will alter its rules based on the Court s findings.

In May 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) addressing recognition of revenue from contracts with customers. When adopted, this guidance will supersede current revenue recognition rules currently followed by the Company. The core principle of the new ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The ASU provides five steps for an entity to apply in recognizing revenue, including: (1) identify the customer contract; (2) identify the contractual performance obligations; (3) determine the transaction price; (4) allocate the transaction price to the contractual performance obligations; and (5) recognize revenue when the performance obligation is satisfied. The new ASU also requires additional disclosures regarding significant contracts with customers. The new ASU will be effective for the Company on January 1, 2017, and early adoption is not permitted. For transition purposes, the new ASU permits either (a) a retrospective application to all years presented, or (b) an alternative transition method whereby the new guidance is only applied to contracts not completed at the date of initial application. The vast majority of the Company s revenue is recognized when oil and natural gas produced by the Company is delivered and legal ownership of these products has transferred to the purchaser. Based on the Company s present understanding, the accounting for oil and gas sales revenue is not expected to be significantly altered by the new ASU. The Company has not yet selected which transition method it will use.

In April 2014, the FASB issued an ASU that will change the requirements for reporting discontinued operations after its adoption. Under the new guidance, only disposals of components of an entity that represent a strategic shift that has or will have a major effect on an entity s operations and financial results will be reported as discontinued operations in the financial statements. Under prior guidance, a component of an entity that is a reportable segment, an operating segment, a reporting unit, a subsidiary, or an asset group that has been or will be eliminated from ongoing operations and for which the Company will not have any significant continuing involvement with the component after the disposal was generally reported as discontinued operations. The FASB anticipates that fewer component disposals will be reported as discontinued operations under the new guidance. The new guidance also requires expanded disclosures about discontinued operations. The new guidance will be effective for the Company beginning in 2015. The new guidance is not to be applied to a component that is classified as held for sale before the effective date of the guidance.

**Outlook**

Average worldwide crude oil prices in July 2014 were similar to the average price during the second quarter of 2014, with certain indices trading higher and certain below the prior quarter. North American natural gas prices, however, have weakened in July 2014 principally due to milder than normal summer temperatures across much of the continent. The Company expects its total oil and natural gas production to average 225,000 barrels of oil equivalent per day in the third quarter 2014. The Company currently anticipates total capital expenditures for the full year 2014 to be approximately $3.8 billion.

*ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)*

**Outlook** ***(Contd.)***

The Company will primarily fund its capital program in 2014 using operating cash flow, but will supplement funding where necessary using borrowings under available credit facilities. The Company s 2014 budget calls for borrowings of long-term debt during the year to fund a portion of the capital program. If oil and/or natural gas prices weaken, actual cash flow generated from operations could be reduced such that higher than anticipated borrowings might be required during the year to maintain funding of the Company s ongoing development projects.

The Company has announced that it plans to exit the U.K. refining and marketing business. On July 31, 2014, the Company signed an agreement to sell the Milford Haven, Wales, refinery and terminal assets. Pending regulatory approval and subject to other material conditions, this transaction is scheduled to be completed by October 31, 2014. Additionally, the Company continues to advance the negotiation for sale of the U.K. marketing business. Should the Company be unable to complete the sale of its U.K. refining and marketing assets on acceptable terms, borrowings under credit facilities at the end of 2014 would be at a higher level than if the sale is successfully completed and the available funds repatriated to the U.S. during 2014. The ultimate completion of the process to exit the U.K. refining and marketing business could lead to future financial accounting losses for the Company.

Should oil and/or natural gas prices weaken significantly in the future, it is possible that certain investments in oil properties could become impaired in a future period.

Through July 31, 2014, the Company has entered into derivative or forward fixed-price delivery contracts to manage risk associated with certain future oil and natural gas sales prices as follows:

| Commodities | Contract or Location | Dates | Average Volumes per Day | Average Prices |
|---|---|---|---|---|
| U.S. Oil | West Texas Intermediate | Jul. Sep. 2014 | 26,000 bbls/d | $94.89 per bbl. |
| | | Oct. Dec. 2014 | 16,000 bbls/d | $92.33 per bbl. |
| Canadian Natural Gas | TCPL NOVA System | Jul. Dec.2014 | 110 mmcf/d | Cdn$4.04 per mcf |
| | | Jan. Dec. 2015 | 65 mmcf/d | Cdn$4.13 per mcf |
| | | Jan. Dec. 2016 | 10 mmcf/d | Cdn$4.13 per mcf |
| Canadian Heavy Oil | Seal Blend | Jul. Sep.2014 | 4,000 bbls/d | $56.14 per bbl.* |
| | | Oct. Dec. 2014 | 4,000 bbls/d | $53.63 per bbl.* |

* Represents average netback prices to the Company.

**Forward-Looking Statements**

This Form 10-Q contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. These statements, which express management s current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of our exploration programs, our ability to maintain production rates and replace reserves, customer demand for our products, adverse foreign exchange movements, political and regulatory instability, and uncontrollable natural hazards. Factors that could cause the sale of the Company s U.K. downstream business, as discussed in this Form 10-Q, not to occur include, but are not limited to, a failure to obtain necessary regulatory approvals, a deterioration in the business or prospects of Murphy or its U.K. downstream subsidiary, adverse developments in Murphy or its U.K. downstream subsidiary s markets, adverse developments in the U.S. or global capital markets, credit markets or economies generally, and a failure to execute a sale of these U.K. operations on acceptable terms. For further discussion of risk factors, see Murphy s 2013 Annual Report on Form 10-K on file with the U.S. Securities and Exchange Commission. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

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### *ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

The Company is exposed to market risks associated with interest rates, prices of crude oil, natural gas and petroleum products, and foreign currency exchange rates. As described in Note K to this Form 10-Q report, Murphy makes use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions.

There were commodity derivative contracts in place at June 30, 2014 covering certain future U.S. crude oil sales volumes in 2014. A 10% increase in the respective benchmark price of these commodities would have increased the recorded net liability associated with these derivative contracts by approximately $40.0 million, while a 10% decrease would have reduced the recorded net liability by a similar amount.

There were derivative foreign exchange contracts in place at June 30, 2014 to hedge the value of the U.S. dollar against the Canadian dollar during July 2014. A 10% strengthening of the U.S. dollar against the Canadian dollar would have decreased the recorded net asset associated with these contracts by approximately $3.1 million, while a 10% weakening of the U.S. dollar would have increased the recorded net asset by approximately $3.7 million. Changes in the fair value of these derivative contracts generally offset the financial statement impact of an equivalent volume of foreign currency exposures associated with other assets and/or liabilities.

### *ITEM 4. CONTROLS AND PROCEDURES*

Under the direction of its principal executive officer and principal financial officer, controls and procedures have been established by the Company to ensure that material information relating to the Company and its consolidated subsidiaries is made known to the officers who certify the Company s financial reports and to other members of senior management and the Board of Directors.

Based on the Company s evaluation as of the end of the period covered by the filing of this Quarterly Report on Form 10-Q, the principal executive officer and principal financial officer of Murphy Oil Corporation have concluded that the Company s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed by Murphy Oil Corporation in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

There have been no changes in the Company s internal control over financial reporting during the quarter ended June 30, 2014 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

## PART II OTHER INFORMATION

### *ITEM 1. LEGAL PROCEEDINGS*

Murphy is engaged in a number of legal proceedings, all of which Murphy considers routine and incidental to its business. Based on information currently available to the Company, the ultimate resolution of environmental and legal matters referred to in this note is not expected to have a material adverse effect on the Company s net income, financial condition or liquidity in a future period.

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**PART II OTHER INFORMATION** ***(Contd.)***

***ITEM 1A. RISK FACTORS***

The Company s operations in the oil and gas business naturally lead to various risks and uncertainties. These risk factors are discussed in Item 1A. Risk Factors in our 2013 Form 10-K filed on February 28, 2014. A risk factor not previously disclosed in its 2013 Form 10-K report is included below.

***Hydraulic fracturing exposes the Company to operational and regulatory risks.***

The Company uses a technique known as hydraulic fracturing whereby water, sand and other chemicals are injected into deep oil and gas bearing reservoirs. This process creates fractures in the rock formation within the reservoir which enables oil and natural gas to migrate to the wellbore. The Company primarily uses this technique in the Eagle Ford Shale in South Texas and in Western Canada. Our hydraulic fracturing operations subject us to operational risks inherent in the drilling and production of oil and natural gas, including relating to underground migration or surface spillage due to releases of oil, natural gas, formation water or well fluids, as well as any related surface or ground water contamination, including from petroleum constituents or hydraulic fracturing chemical additives. Ineffective containment of surface spillage and surface or ground water contamination resulting from our hydraulic fracturing operations, including from petroleum constituents or hydraulic fracturing chemical additives, could result in environmental pollution, remediation expenses and third party claims alleging damages, which could adversely affect our financial condition and results of operations. In addition, hydraulic fracturing requires significant quantities of water. Any diminished access to water for use in the process could curtail our operations or otherwise result in operational delays or increased costs.

Hydraulic fracturing is generally regulated by the states, although certain hydraulic fracturing activities are also subject to existing and proposed federal regulations, including pursuant to the Safe Drinking Water Act and the Clean Air Act. In June 2011, the State of Texas adopted a law requiring public disclosure of information regarding components used in the hydraulic fracturing process. Similar disclosure requirements have also been implemented or proposed in other states and by the United States. The Canadian provinces of British Columbia and Alberta have also issued regulations related to hydraulic fracturing activities under their jurisdictions. It is possible that these and other jurisdictions may adopt further laws or regulations which could render the process less effective, drive up its costs or otherwise prohibit hydraulic fracturing activities in certain locations. If any such action is taken in the future, our production levels could be adversely affected or our costs of drilling and completion could be increased.

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***ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS***

Murphy Oil Corporation

Issuer Purchases of Equity Securities

| 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[1] |
|---|---|---|---|---|
| April 1, 2014 to April 30, 2014 | | $ | | $ |
| May 1, 2014 to May 31, 2014 | 1,973,417 | 67.57[2] | 1,973,417[1,2] | |
| June 1, 2014 to June 30, 2014 | | | | |
| **Total April 1, 2014 to June 30, 2014** | **1,973,417** | **63.34** | **1,973,417** | |

1 On February 5, 2014, the Company announced that it had entered into a variable term, capped accelerated share repurchase transaction (ASR) with a major financial institution to repurchase an aggregate of $250 million of the Company s Common stock. The total aggregate number of shares repurchased pursuant to this ASR was determined by reference to the Rule 10b-18 volume-weighted price of the Company s Common stock, less a fixed discount, over the term of the ASR, subject to a minimum number of shares. The ASR was completed in May 2014 and the Company received an additional 123,380 shares upon completion of the ASR program. This brought the total number of shares acquired under this ASR transaction to 4,141,452, with the average purchase price equal to $60.37 per share. This transaction completed the $1.0 billion stock buyback program authorized by the Company s Board of Directors as announced on October 16, 2012.

2 On May 20, 2014, the Company announced that it had entered into a $125 million variable term, capped ASR transaction with a major financial institution. The ASR transaction was structured similarly to the previous ASR transactions. In May, the Company received the minimum number of shares under the transaction, which totaled 1,850,037 shares. Additional shares may be received upon maturity of this ASR transaction in the third quarter of 2014.

***ITEM 6. EXHIBITS***

The Exhibit Index on page 36 of this Form 10-Q report lists the exhibits that are hereby filed or incorporated by reference.

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**SIGNATURE**

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.

***MURPHY OIL CORPORATION***

*(Registrant)*

By /s/ JOHN W. ECKART
John W. Eckart, Senior Vice President and Controller *(Chief Accounting Officer and Duly Authorized Officer)*

August 5, 2014

*(Date)*

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**EXHIBIT INDEX**

| Exhibit No. | |
|---|---|
| 4.1 | 5-Year Revolving Credit Agreement dated June 14, 2011 |
| 4.2 | Commitment Increase and Maturity Extension Agreement dated May 23, 2013. |
| 12 | Computation of Ratio of Earnings to Fixed Charges |
| 31.1 | Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32 | Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101. INS | XBRL Instance Document |
| 101. SCH | XBRL Taxonomy Extension Schema Document |
| 101. CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101. DEF | XBRL Taxonomy Extension Definition Linkbase Document |
| 101. LAB | XBRL Taxonomy Extension Labels Linkbase Document |
| 101. PRE | XBRL Taxonomy Extension Presentation Linkbase |

Exhibits other than those listed above have been omitted since they are either not required or not applicable.