MURPHY OIL CORP /DE
Form 10-Q
August 04, 2016

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, 2016

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 (State or other jurisdiction of incorporation or organization)	71-0361522 (I.R.S. Employer Identification Number)
300 Peach Street, P.O. Box 7000, El Dorado, Arkansas (Address of principal executive offices)	71731-7000 (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, 2016 was 172,199,108.

MURPHY OIL CORPORATION

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PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED BALANCE SHEETS (unaudited)

(Thousands of dollars)

	June 30, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 267,483	283,183
Canadian government securities with maturities greater than 90 days at the date of acquisition	131,224	173,288
Accounts receivable, less allowance for doubtful accounts of $1,605 in 2016 and 2015	293,312	522,672
Inventories, at lower of cost or market		
Crude oil	8,654	25,583
Materials and supplies	145,413	141,205
Prepaid expenses	113,563	212,962
Deferred income taxes	46,093	51,183
Assets held for sale	32,113	38,340
Total current assets	1,037,855	1,448,416
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $12,241,549 in 2016 and $11,924,193 in 2015	8,565,485	9,818,365
Deferred charges and other assets	311,292	227,031
Total assets	$ 9,914,632	11,493,812
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 20,011	18,881
Accounts payable and accrued liabilities	843,787	1,643,632
Income taxes payable	12,816	4,819
Liabilities associated with assets held for sale	4,135	7,297
Total current liabilities	880,749	1,674,629
Long-term debt, including capital lease obligation	2,435,486	3,040,594
Deferred income taxes	46,749	239,811
Asset retirement obligations	746,361	793,474

Deferred credits and other liabilities	633,594	438,576
Stockholders' equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	–	–
Common Stock, par $1.00, authorized 450,000,000 shares, issued 195,055,724 shares in 2016 and 2015	195,056	195,056
Capital in excess of par value	914,236	910,074
Retained earnings	5,895,794	6,212,201
Accumulated other comprehensive loss	(536,659)	(704,542)
Treasury stock, 22,856,616 shares of Common Stock in 2016 and 23,021,013 shares of Common Stock in 2015, at cost	(1,296,734)	(1,306,061)
Total stockholders' equity	5,171,693	5,306,728
Total liabilities and stockholders' equity	$ 9,914,632	11,493,812

See Notes to Consolidated Financial Statements, page 7.

The Exhibit Index is on page 34.

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Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF OPERATIONS (unaudited)

(Thousands of dollars, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30, June 30,	
	2016	2015	2016	2015
REVENUES				
Sales and other operating revenues	$ 411,217	718,621	840,311	1,467,771
Gain on sale of assets	3,809	18,246	3,831	154,123
Interest and other income	22,436	1,423	23,615	38,143
Total revenues	437,462	738,290	867,757	1,660,037
COSTS AND EXPENSES				
Lease operating expenses	156,530	227,489	315,633	459,910
Severance and ad valorem taxes	13,439	19,043	26,076	39,834
Exploration expenses, including undeveloped lease amortization	37,128	64,959	64,044	193,693
Selling and general expenses	67,113	79,176	140,620	166,143
Depreciation, depletion and amortization	255,239	403,390	541,388	884,417
Impairment of assets	–	–	95,088	–
Accretion of asset retirement obligations	12,346	11,750	24,471	23,519
Interest expense	35,058	30,466	67,119	59,936
Interest capitalized	(608)	(1,823)	(2,449)	(3,208)
Other expense (benefit)	(7,516)	13,931	(7,932)	63,612
Total costs and expenses	568,729	848,381	1,264,058	1,887,856
Loss from continuing operations before income taxes	(131,267)	(110,091)	(396,301)	(227,819)
Income tax benefit	(134,172)	(21,105)	(199,721)	(142,363)
Income (loss) from continuing operations	2,905	(88,986)	(196,580)	(85,456)
Income (loss) from discontinued operations, net of income taxes	25	15,152	708	(2,819)
NET LOSS (INCOME)	$ 2,930	(73,834)	(195,872)	(88,275)
PER COMMON SHARE – BASIC				
Income (loss) from continuing operations	$ 0.02	(0.51)	(1.14)	(0.48)
Income (loss) from discontinued operations	-	0.09	-	(0.02)
Net income (loss)	$ 0.02	(0.42)	(1.14)	(0.50)
PER COMMON SHARE – DILUTED				
Income (loss) from continuing operations	$ 0.02	(0.51)	(1.14)	(0.48)
Income (loss) from discontinued operations	-	0.09	-	(0.02)
Net income (loss)	$ 0.02	(0.42)	(1.14)	(0.50)

Average Common shares outstanding				
Basic	172,196,914	174,488,842	172,149,791	176,343,309
Diluted	172,799,827	174,488,842	172,149,791	176,343,309

See Notes to Consolidated Financial Statements, page 7.

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Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (unaudited)

(Thousands of dollars)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
Net income (loss)	$ 2,930	(73,834)	(195,872)	(88,275)
Other comprehensive income (loss), net of tax				
Net gain (loss) from foreign currency translation	13,222	31,981	161,891	(266,614)
Retirement and postretirement benefit plans	2,513	2,695	5,029	5,989
Deferred loss on interest rate hedges reclassified to interest expense	481	481	963	963
Other comprehensive income (loss)	16,216	35,157	167,883	(259,662)
COMPREHENSIVE INCOME (LOSS)	$ 19,146	(38,677)	(27,989)	(347,937)

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, 2016	2015
OPERATING ACTIVITIES		
Net loss	$ (195,872)	(88,275)
Adjustments to reconcile net loss to net cash provided by continuing operations activities:		
(Income) loss from discontinued operations	(708)	2,819
Depreciation, depletion and amortization	541,388	884,417
Impairment of assets	95,088	–
Amortization of deferred major repair costs	3,798	3,404
Dry hole costs	14,270	99,023
Amortization of undeveloped leases	25,419	45,825
Accretion of asset retirement obligations	24,471	23,519
Deferred and noncurrent income tax benefits	(316,201)	(194,240)
Pretax gains from disposition of assets	(3,831)	(154,123)
Net (increase) decrease in noncash operating working capital	(86,793) 1	107,171
Other operating activities, net	12,349	(14,329)
Net cash provided by continuing operations activities	113,378	715,211
INVESTING ACTIVITIES		
Property additions and dry hole costs	(604,587)	(1,433,615)
Proceeds from sales of property, plant and equipment	1,153,325	423,106
Purchase of investment securities2	(651,218)	(629,763)
Proceeds from maturity of investment securities2	701,378	663,343
Other investing activities, net	(7,640)	(20,568)
Net cash provided (required) by investing activities	591,258	(997,497)
FINANCING ACTIVITIES		
Borrowings of debt	–	823,000
Repayments of debt	(600,000)	(450,000)
Capital lease obligation payments	(5,172)	(4,703)
Purchase of treasury stock	–	(250,000)
Withholding tax on stock-based incentive awards	(1,138)	(8,976)
Cash dividends paid	(120,535)	(124,581)
Other financing activities, net	–	(152)
Net cash required by financing activities	(726,845)	(15,412)
CASH FLOWS FROM DISCONTINUED OPERATIONS		
Operating activities	5,185	(85,445)
Investing activities	–	5,322
Changes in cash included in current assets held for sale	(5,185)	89,226

Net increase in cash and cash equivalents of discontinued operations	–	9,103
Effect of exchange rate changes on cash and cash equivalents	6,509	4,555
Net decrease in cash and cash equivalents	(15,700)	(284,040)
Cash and cash equivalents at January 1	283,183	1,193,308
Cash and cash equivalents at June 30	$ 267,483	909,268

12016 balance includes payments for deepwater rig contract exit of $261.8 million.

2Investments 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, 2016	2015
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	$ –	–
Common Stock – par $1.00, authorized 450,000,000 shares, issued 195,055,724 shares at June 30, 2016 and June 30, 2015		
Balance at beginning of period	195,056	195,040
Exercise of stock options	–	16
Balance at end of period	195,056	195,056
Capital in Excess of Par Value		
Balance at beginning of period	910,074	906,741
Exercise of stock options, including income tax benefits	–	(376)
Restricted stock transactions and other	(10,078)	(38,032)
Stock-based compensation	14,454	24,285
Other	(214)	(65)
Balance at end of period	914,236	892,553
Retained Earnings		
Balance at beginning of period	6,212,201	8,728,032
Net loss for the period	(195,872)	(88,275)
Cash dividends	(120,535)	(124,581)
Balance at end of period	5,895,794	8,515,176
Accumulated Other Comprehensive Loss		
Balance at beginning of period	(704,542)	(170,255)
Foreign currency translation gain (loss), net of income taxes	161,891	(266,614)
Retirement and postretirement benefit plans, net of income taxes	5,029	5,989
Deferred loss on interest rate hedges reclassified to interest expense, net of income taxes	963	963
Balance at end of period	(536,659)	(429,917)
Treasury Stock		
Balance at beginning of period	(1,306,061)	(1,086,124)
Purchase of treasury shares	–	(250,000)

Sale of stock under employee stock purchase plans	334	246
Awarded restricted stock, net of forfeitures	8,993	29,056
Balance at end of period – 22,856,616 shares of Common Stock in 2016 and 22,303,782 shares of Common Stock in 2015, at cost	(1,296,734)	(1,306,822)
Total Stockholders’ Equity	$ 5,171,693	7,866,046

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 – Nature of Business and Interim Financial Statements

NATURE OF BUSINESS – Murphy Oil Corporation is an international oil and gas company that conducts its business through various operating subsidiaries. The Company produces oil and natural gas in the United States, Canada and Malaysia and conducts oil and natural gas exploration activities worldwide. The Company sold its interest in a Canadian synthetic oil operation in the second quarter of 2016. The Company acquired 70% interest in Duvernay Shale and a 30% interest in liquids rich Montney properties during the second quarter 2016.

INTERIM FINANCIAL STATEMENTS – 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, 2016 and December 31, 2015, and the results of operations, cash flows and changes in stockholders' equity for the interim periods ended June 30, 2016 and 2015, 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 2015 Form 10-K report, as certain notes and other pertinent information have been abbreviated or omitted in this report. Financial results for the six-month period ended June 30, 2016 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, 2016, the Company had total capitalized exploratory well costs pending the determination of proved reserves of $128.1 million. The following table reflects the net changes in capitalized exploratory well costs during the

six-month periods ended June 30, 2016 and 2015.

(Thousands of dollars)	2016	2015
Beginning balance at January 1	$ 130,514	120,455
Additions pending the determination of proved reserves	800	1,620
Other adjustments	(3,205)	–
Balance at June 30	$ 128,109	122,075

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note B – Property, Plant and Equipment (Contd.)

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, 2016			2015		
(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	$ 63,617	5	5	$ 217	2	1
One to two years	–	–	–	32,192	2	1
Two to three years	31,627	2	–	27,842	2	–
Three years or more	32,865	4	–	61,824	4	2
	$ 128,109	11	5	$ 122,075	10	4

Exploratory well costs capitalized more than one year at June 30, 2016 are in Brunei, and development options are under review for these multiple gas discoveries.

In April 2016, a Canadian subsidiary of the Company signed a purchase and sale agreement for the sale of its five percent, non-operated working interest in Syncrude Canada Ltd. ("Syncrude") asset to Suncor Energy Inc. ("Suncor"), subject to closing adjustments. The sale was completed in June 2016 and the Company received net cash proceeds of $739.1 million. The Company recorded an after-tax gain of $71.7 million in the second quarter of 2016 associated with the Syncrude divestiture.

In April 2016, a Canadian subsidiary of the Company completed its transaction to divest natural gas processing and sales pipeline assets that support Murphy's Montney natural gas fields in the Tupper area of northeastern British Columbia. Total cash consideration received by Murphy upon closing of the transaction was $414.1 million. A gain on sale of approximately $187 million is being deferred and recognized over the next 20 years in the Canadian operating segment. The Company amortized $1.8 million of the deferred gain in the second quarter of 2016. The remaining deferred gain is included as a component of deferred credits and other liabilities on the Company's consolidated Balance Sheet.

In a separate transaction, the same Canadian subsidiary signed a definitive agreement to acquire a 70 percent operated working interest (WI) of Athabasca Oil Corporation's (Athabasca) production, acreage, infrastructure and facilities in the Kaybob Duvernay lands, and a 30 percent non-operated WI of Athabasca's production, acreage, infrastructure and facilities in

the liquids rich Montney lands in Alberta, the majority of which is unproved. Under the terms of the joint venture the total consideration amounts to approximately $375 million, of which Murphy paid $206.7 million in cash at closing, subject to normal closing adjustments, and the remaining $168.0 million in the form of a carried interest for a period of up to five years. The transaction closed in the second quarter of 2016.

During the first quarter of 2016, declines in crude oil and natural gas prices from year end 2015 provided indications of possible impairments in certain of the company's producing properties. As a result of management's assessments, the Company recognized pretax non-cash impairments charges of $95.1 million in the six-month period ended June 30, 2016, to reduce the carrying value to their estimated fair value for its Terra Nova field offshore Canada and its Western Canada onshore heavy oil producing properties. The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges, estimates of future costs, and a discount rate believed to be consistent with those used by principal market participants in the region.

During the six-month period ended June 30, 2015, the Company completed the sale of 10% of its oil and gas assets in Malaysia and received net cash proceeds of $417.2 million. The Company recorded an after-tax gain of $199.5 million on the sale in the 2015 six-month period.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note C – Discontinued Operations

The Company has accounted for its U.K. refining and marketing operations as discontinued operations for all periods presented. The Company completed its agreement to sell the remaining U.K. downstream assets at the end of the second quarter of 2015 and results subsequent to the sale are related to winding up of these operations.

The results of operations associated with discontinued operations for the three-month and six-month periods ended June 30, 2016 and 2015 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of dollars)	2016	2015	2016	2015
Revenues	$ 151	153,107	835	382,496
Income before income taxes	$ 25	21,046	708	337
Income tax benefit	–	5,894	–	3,156
Income (loss) from discontinued operations	$ 25	15,152	708	(2,819)

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, 2016 and December 31, 2015.

(Thousands of dollars)	June 30, 2016	December 31, 2015
Current assets		
Cash	$ 3,007	7,927
Accounts receivable	12,403	12,037

Other	16,703	18,376
Total current assets held for sale	$ 32,113	38,340
Current liabilities		
Accounts payable	$ 488	2,433
Accrued compensation and severance	–	2,179
Refinery decommissioning cost	3,647	2,685
Total current liabilities associated with assets held for sale	$ 4,135	7,297

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note D – Financing Arrangements and Debt

The Company has a $2.0 billion committed credit facility with a major banking consortium that expires in June 2017. Borrowings under the facility bear interest at 1.45% above LIBOR based on the Company's current credit rating as of June 30, 2016. In addition, facility fees of 0.30% are charged on the full $2.0 billion commitment. At June 30, 2016, the company had no borrowings under this committed facility. The Company also had outstanding letters of credit of approximately $88 million issued under its revolving credit facility at June 30, 2016, which reduced the available borrowing capacity under the agreement. At June 30, 2016, the Company also had uncommitted credit lines that had an estimated total borrowing capacity of approximately $195 million of which no amounts were outstanding under these uncommitted credit lines. If necessary, the Company believes it could borrow funds under all or certain of these uncommitted lines with various financial institutions in future periods. 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 2018.

The Company and its partners are parties to 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 included $20.0 million and $202.7 million, respectively, associated with this lease at June 30, 2016.

Note E – Cash Flow Disclosures

Additional disclosures regarding cash flow activities are provided below.

	Six Months Ended June 30	
(Thousands of dollars)	2016	2015
Net (increase) decrease in operating working capital other than cash and cash equivalents:		
Decrease in accounts receivable	$ 109,105	284,542
Increase in inventories	(4,659)	(25,547)

Decrease (increase) in prepaid expenses	99,524	(40,191)
Decrease in deferred income tax assets	5,564	5,092
Decrease in accounts payable and accrued liabilities	(337,302)	(84,781)
Increase (decrease) in current income tax liabilities	40,975	(31,944)
Net (increase) decrease in noncash operating working capital	$ (86,793)	107,171
Supplementary disclosures:		
Cash income taxes paid (refunded), net	$ (4,367)	90,419
Interest paid, net of amounts capitalized	52,654	55,658
Non-cash investing activities:		
Asset retirement costs capitalized	$ 8,693	6,703
Decrease in capital expenditure accrual	165,329	336,952

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note F – 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.

The table that follows provides the components of net periodic benefit expense for the three-month and six-month periods ended June 30, 2016 and 2015.

	Three Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2016	2015	2016	2015
Service cost	$ 2,770	4,772	675	828
Interest cost	8,865	7,971	1,107	1,192
Expected return on plan assets	(9,698)	(8,724)	–	–
Amortization of prior service cost	321	198	(20)	(20)
Amortization of transitional asset	–	274	2	3
Recognized actuarial loss	3,718	3,891	36	190
	5,976	8,382	1,800	2,193
Special termination benefits	–	8,606	–	–
Curtailments	–	306	–	–
Net periodic benefit expense	$ 5,976	17,294	1,800	2,193

	Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2016	2015	2016	2015

Service cost	$ 5,923	9,853	1,348	1,656
Interest cost	14,473	15,921	2,215	2,384
Expected return on plan assets	(15,083)	(17,411)	–	–
Amortization of prior service cost	640	393	(41)	(41)
Amortization of transitional asset	–	545	2	3
Recognized actuarial loss	7,247	7,782	75	385
	13,200	17,083	3,599	4,387
Special termination benefits	–	8,606	–	–
Curtailments	822	306	(19)	–
Net periodic benefit expense	$ 14,022	25,995	3,580	4,387

Curtailment expense for the six months ended June 30, shown in the table above, relates to restructuring activities in the U.S. undertaken by the Company in the first quarter 2016. During the six-month period ended June 30, 2016, the Company made contributions of $6.7 million to its defined benefit pension and postretirement benefit plans. Remaining required funding in 2016 for the Company's defined benefit pension and postretirement plans is anticipated to be $6.3 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note G – 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 (RSU), 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.

In February 2016, the Committee granted stock options for 862,000 shares at an exercise price of $17.57 per share. The Black-Scholes valuation for these awards was $5.03 per option. The Committee also granted 394,000 performance-based RSU and 200,000 time-based RSU in February. The fair value of the performance-based RSU, using a Monte Carlo valuation model, ranged from $12.21 to $16.34 per unit. The fair value of time-based RSU was estimated based on the fair market value of the Company's stock on the date of grant, which was $17.57 per share. Additionally, the Committee granted 708,200 SAR and 507,470 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. Also in February, the Committee granted 85,679 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 estimated fair value of these awards was $19.26 per unit on date of grant. In April 2016, the Company awarded an additional 217,500 time-based RSU. The fair value of these time-based RSU was estimated based on the fair market value of the Company's stock on the date of grant, which was $24.075 per share.

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

	Six Months Ended June 30,	
(Thousands of dollars)	2016	2015
Compensation charged against income before tax benefit	$ 24,288	31,230
Related income tax benefit recognized	8,210	9,691

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note H – Earnings per Share

Net income (loss) was used as the numerator in computing both basic and diluted income per Common share for the

three-months and six-month periods ended June 30, 2016 and 2015. 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)	2016	2015	2016	2015
Basic method	172,196,914	174,488,842	172,149,791	176,343,309
Dilutive stock options*	602,913	–	–	–
Diluted method	172,799,827	174,488,842	172,149,791	176,343,309

*Due to a net loss recognized by the Company for the three-month period ended June 30, 2015 and six-month periods ended June 30, 2016 and 2015, no unvested stock awards were included in the computation of diluted earnings per share because the effect would have been anti-dilutive.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Antidilutive stock options excluded from diluted shares	5,084,395	5,988,668	5,799,268	5,767,975
Weighted average price of these options	$ 54.22	$ 53.12	50.17	53.31

Note I – Income Taxes

The Company's effective income 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 2016 and 2015, the Company's effective income tax rates were as follows:

	2016	2015
Three months ended June 30	102.2%	19.2%
Six months ended June 30	50.4%	62.5%

The effective tax rates for most periods where earnings are generated, generally exceed 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. Conversely, the effective tax rates for most periods where losses are incurred generally are lower than U.S. statutory tax rate of 35% due to similar reasons. The effective tax rate for both the three-month and six-month periods ended June 30, 2016 was above the U.S. statutory tax rate primarily due to deferred tax benefits recognized related to the Canadian asset dispositions and income tax benefits on investments in foreign areas. The effective tax rate for the three-month period ended June 30, 2015 was less than the U.S. statutory tax rate primarily due to a deferred tax expense associated with an enacted increase in the statutory tax rate in Alberta. The effective tax rate for the six-month period ended June 30, 2015 was above the U.S. statutory tax rate primarily due to a deferred tax benefit associated with the sale of Malaysian assets, partially offset by other expenses in foreign jurisdictions for which no tax benefits were recognized and the enacted increase in statutory rate in Alberta.

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, 2016, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States – 2011; Canada – 2008; Malaysia – 2009; and United Kingdom – 2014.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note J – Financial Instruments and Risk Management

Murphy often uses 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, such as the New York Mercantile Exchange (NYMEX). 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 gains and losses on these derivative contracts in its Consolidated Statements of Operations. Certain interest rate derivative contracts were accounted for as hedges and the net payment upon settlement recording the fair value of these contracts was deferred in Accumulated Other Comprehensive Loss. This deferred cost is being reclassified to Interest Expense in the Consolidated Statements of Operations 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, natural gas liquids and natural gas it produces and sells. The Company had open derivative contracts at June 30, 2016 and 2015. The impact from marking to market these commodity derivative contracts increased the loss before income taxes by $2.6 million for the six-month period ended June 30, 2016 and reduced the loss before income taxes by $7.4 million for the six-month period ended June 30, 2015.

Open West Texas Intermediate (WTI) contracts were as follows:

At June 30, 2016	Volumes (barrels per day)	Swap Prices
July – December 2016	25,000	$50.67 per barrel

January – December 2017	7,000	$50.16 per barrel
At June 30, 2015		
July – September 2015	15,000	$62.84 per barrel
October – December 2015	15,000	$63.30 per barrel

Foreign Currency Exchange Risks

The Company is subject to foreign currency exchange risk associated with operations in countries outside the U.S. At June 30, 2016 and 2015 short-term derivative instruments were outstanding in Canada for approximately $5.8 million and $8.0 million, respectively, to manage the currency risks of certain U.S. dollar accounts receivable associated with sale of Canadian crude oil. The impact from marking to market these foreign currency derivative contracts was insignificant for the six-month periods ended June 30, 2016 and 2015, respectively.

After signing an agreement to sell its five percent non-operated working interest in Syncrude, the Company's Canadian subsidiary entered into forward sales contracts for C$1.0 billion at a fixed rate to lock in the U.S. dollar value of the proceeds and protect the Company from exposure to weakening of the Canadian dollar. Upon completion of the sale and settlement of the forward sale contracts, the Company recognized income of approximately $26.8 million in the second quarter of 2016 due to weakening of the Canadian dollar subsequent to entering into the contracts.

At June 30, 2016 and December 31, 2015, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

	June 30, 2016		December 31, 2015	
(Thousands of dollars)	Asset (Liability) Derivatives		Asset (Liability) Derivatives	
Type of Derivative Contract	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity	Accounts receivable	$ 1,709	Accounts receivable	$ 89,358
Foreign exchange	Accounts payable	(1)	Accounts payable	(29)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note J – Financial Instruments and Risk Management (Contd.)

For the three-month and six-month periods ended June 30, 2016 and 2015, the gains and losses recognized in the Consolidated Statements of Operations for derivative instruments not designated as hedging instruments are presented in the following table.

		Gain (Loss)			
		Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of dollars) Type of Derivative Contract	Statement of Operations Location	2016	2015	2016	2015
Commodity	Sales and other operating revenues	$ (47,738)	7,419	(34,549)	7,419
Foreign exchange	Interest and other income	26,481	(49)	26,786	14
		$ (21,257)	7,370	(7,763)	7,433

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 the net cost associated with these contracts to match the payment of interest on these notes through 2022. During each of the six-month periods ended June 30, 2016 and 2015, $1.5 million of the deferred loss on the interest rate swaps was charged to Interest expense in the Consolidated Statement of Operations. The remaining loss deferred on these matured contracts at June 30, 2016 was $11.3 million, which was recorded, net of income taxes of $6.1 million, in Accumulated Other Comprehensive Loss in the Consolidated Balance Sheet. The Company expects to charge approximately $1.5 million of this deferred loss to Interest expense in the Consolidated Statement of Operations during the remaining six months of 2016.

Fair Values – Recurring

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, 2016 and December 31, 2015 are presented in the following table.

	June 30, 2016				December 31, 2015			
(Thousands of dollars)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Commodity derivative contracts	–	1,709	–	1,709	–	89,358	–	89,358
	$ –	1,709	–	1,709	–	89,358	–	89,358
Liabilities:								
Nonqualified employee savings plans	$ 13,256	–	–	13,256	12,971	–	–	12,971
Foreign currency exchange derivative contracts	–	1	–	1	–	29	–	29
	$ 13,256	1	–	13,257	12,971	29	–	13,000

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note J – Financial Instruments and Risk Management (Contd.)

The fair value of WTI crude oil derivative contracts was determined based on active market quotes for WTI crude oil at the balance sheet date. The fair value of foreign exchange derivative contracts in each year 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 Operations while the effects of 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 Operations. 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, 2016 and December 31, 2015.

Fair Values – Nonrecurring

As a result of significantly lower commodity prices in early 2016, the Company recognized $95.1 million in pretax noncash impairment charges related to producing properties during the six-month period ended June 30, 2016. The fair value information associated with these impaired properties is presented in the following table.

	June 30, 2016				
	Fair Value				
	Level 1	Level 2	Level 3	Net Book Value Prior to Impairment	Total Pretax (Noncash) Impairment Loss
(Thousands of dollars)					
Assets:					
Impaired proved properties					
Canada	$ –	–	71,967	167,055	95,088

The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges, estimates of future costs and a discount rate believed to be consistent with those used by principal market participants in the applicable region.

Note K – Accumulated Other Comprehensive Loss

The components of Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets at December 31, 2015 and June 30, 2016 and the changes during the six-month period ended June 30, 2016 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, 2015	$	(513,004)	(179,260)	(12,278)	(704,542)
Components of other comprehensive income:					
Before reclassifications to income		161,891	(3)	–	161,888
Reclassifications to income		–	5,032 [2]	963 [3]	5,995
Net other comprehensive income		161,891	5,029	963	167,883
Balance at June 30, 2016	$	(351,113)	(174,231)	(11,315)	(536,659)

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

[2]Reclassifications before taxes of $7,741 for the six-month period ended June 30, 2016 are included in the computation of net periodic benefit expense. See Note G for additional information. Related income taxes of $2,709 for the six-month period ended June 30, 2016 are included in Income tax expense.

[3]Reclassifications before taxes of $1,482 for the six-month period ended June 30, 2016 are included in Interest expense. Related income taxes of $519 for the six-month period ended June 30, 2016 are included in Income tax expense.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note L – 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.

During 2015, the Company's subsidiary in Canada identified a leak or leaks at an infield condensate transfer pipeline at the Seal field in a remote area of Alberta. The pipeline was immediately shut down and the Company's emergency response plan was activated. In cooperation with local governmental regulators, and with the assistance of qualified consultants, an investigation and remediation plan is progressing as planned and the Company's insurers have been notified. The Company has not yet established a complete estimate of the costs to remediate the site. Based on the assessments done to date, the Company recorded $43.9 million in other expense during 2015 associated with the estimated costs of remediating the site. The Company has spent $32.7 million to date associated with this event. Further refinements in the estimated total cost to remediate the site are anticipated in future periods, including possible fines from regulators and insurance recoveries. It is possible that the ultimate net remediation costs to the Company associated with the condensate leak or leaks will exceed the amount of expense recorded through June 30, 2016.

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 M – Commitments

The Company has entered into forward sales contracts to mitigate the price risk for a portion of its 2016 to 2020 natural gas sales volumes in Western Canada. The natural gas sales contracts call for deliveries during the last six months of 2016 of approximately 99 million cubic feet per day (MMCFD) at C$3.00 per MCF and 40 MMCFD at C$2.71 per MCF from January 2017 through December 2020. In July 2016, the Company entered into an additional 19 MMCFD of natural gas sales contracts for the January 2017 through December 2020 period at C$3.00 per MCF. These natural gas contracts have been accounted for as normal sales for accounting purposes.

Note N – Business Segments

		Three Months Ended		Three Months Ended	
	Total Assets at June 30,	June 30, 2016		June 30, 2015	
		External	Income	External	Income
(Millions of dollars)	2016	Revenues	(Loss)	Revenues	(Loss)
Exploration and production*					
United States	$ 5,479.2	143.6	(65.7)	339.8	(16.5)
Canada	1,580.3	77.4	55.3	152.9	(32.2)
Malaysia	2,130.4	190.5	47.7	244.5	27.6
Other	133.2	(0.1)	(5.1)	–	(30.1)
Total exploration and production	9,323.1	411.4	32.2	737.2	(51.2)
Corporate	559.4	26.1	(29.3)	1.1	(37.8)
Assets/revenue/income (loss) from continuing operations	9,882.5	437.5	2.9	738.3	(89.0)
Discontinued operations, net of tax	32.1	–	–	–	15.2
Total	$ 9,914.6	437.5	2.9	738.3	(73.8)
		Six Months Ended		Six Months Ended	
		June 30, 2016		June 30, 2015	
		External	Income	External	Income

(Millions of dollars)		Revenues	(Loss)	Revenues	(Loss)
Exploration and production*					
United States	$	318.3	(131.4)	619.9	(110.4)
Canada		183.5	(31.9)	305.2	(70.7)
Malaysia		338.8	70.1	690.2	250.7
Other		–	(31.2)	–	(102.1)
Total exploration and production		840.6	(124.4)	1,615.3	(32.5)
Corporate		27.2	(72.2)	44.7	(53.0)
Revenue/income (loss) from continuing operations		867.8	(196.6)	1,660.0	(85.5)
Discontinued operations, net of tax		–	0.7	–	(2.8)
Total	$	867.8	(195.9)	1,660.0	(88.3)

*Additional details about results of oil and gas operations are presented in the tables on pages 26 and 27.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note O – New Accounting Principles and Recent Accounting Pronouncements

Leases

In February 2016, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) to increase transparency and comparability among companies by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous generally accepted accounting principles (GAAP) and this ASU is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. The new standard is effective for financial statements issued for annual periods beginning after December 15, 2018 and interim periods within those annual periods. Early adoption is permitted for all entities. The Company anticipates adopting this guidance in 2019 and is currently evaluating the standard and its impact on its consolidated financial statements and footnote disclosures.

Compensation-Stock Compensation

In March 2016, the FASB issued an ASU intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification within the statement of cash flows. The amendments in this ASU are effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early adoption is permitted for any entity in any interim period or annual period. The Company will adopt this guidance in 2017 and is currently evaluating the impact on its consolidated financial statements and footnote disclosures.

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), a comprehensive new revenue recognition standard for contracts with customers that will supersede most current revenue recognition requirements and industry-specific guidance. The codification was amended through additional ASUs and, as amended, requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company is required to adopt the new standard in the first quarter of 2018 using either the retrospective or cumulative effect transition method. The Company has not yet selected a transition method and is currently evaluating the standard and the impact on its consolidated financial statements and footnote disclosures.

Note P – Subsequent Event

On August 3, 2016, the Board of Directors of Murphy Oil Corporation declared a quarterly cash dividend on its common stock of $0.25 per share. The dividend is payable September 1, 2016 to holders of record August 15, 2016.

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

Overall Review

During the first half of 2016, worldwide benchmark oil and natural gas prices have been significantly below average comparable benchmark prices during 2015. These lower oil and natural gas prices coupled with a property impairment in the 2016 period have led the Company to incur losses from operations in the first six months of 2016. Although the Company has been aggressively attacking its overall cost structure, a continuation of very low commodity prices would likely lead to further adverse effects on the Company's income and cash flow in future periods.

Results of Operations

Murphy's income by type of business is presented below.

	Income (Loss) Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of dollars)	2016	2015	2016	2015
Exploration and production	$ 32.2	(51.2)	(124.4)	(32.5)
Corporate and other	(29.3)	(37.8)	(72.2)	(53.0)
Income (loss) from continuing operations	2.9	(89.0)	(196.6)	(85.5)
Discontinued operations	–	15.2	0.7	(2.8)
Net income (loss)	$ 2.9	(73.8)	(195.9)	(88.3)

Murphy's net earnings in the second quarter of 2016 was $2.9 million ($0.02 per diluted share) compared to net loss of $73.8 million ($0.42 per diluted share) in the second quarter of 2015. Income from continuing operations was $2.9 million ($0.02 per diluted share) in the 2016 quarter compared to a loss of $89.0 million ($0.51 per diluted share) in 2015. In the 2016 second quarter, the Company's exploration and production continuing operations earned $32.2 million compared to a loss of $51.2 million in the 2015 quarter. The net income in the 2016 quarter was favorably impacted by lower lease operating expenses, lower depreciation expense, lower exploration costs and higher income tax benefits related to capital gains tax treatment on Canadian asset dispositions and income tax benefits recognized on investments in foreign areas. These were offset in part by lower revenues due to significantly weaker realized oil and natural gas sales prices and lower volumes sold. The corporate function had after-tax costs of $29.3 million in the 2016 second quarter compared to after-tax costs of $37.8 million in the 2015 period with the favorable variance in the current period mostly due to higher benefits from foreign exchange effects offset in part by higher net interest costs. The 2016 second quarter included only minor income from discontinued operations compared to income of $15.2 million ($0.09 per diluted share) in the 2015 period. Discontinued operations in the prior period included an adjustment to the impairment previously recognized for refining and marketing operations in the U.K., the final components of which were sold at the end of the second quarter 2015.

For the first six months of 2016, net loss totaled $195.9 million ($1.14 per diluted share) compared to a net loss of $88.3 million ($0.50 per diluted share) for the same period in 2015. Continuing operations had a loss of $196.6 million ($1.14 per diluted share) in the first six months of 2016, compared to a loss of $85.5 million ($0.48 per diluted share) in the same period of 2015. In the first half of 2016, the Company's exploration and production operations incurred a loss of $124.4 million compared to a loss of $32.5 million in the same period of 2015. Exploration and production loss in 2016 was higher than the 2015 period primarily due to lower revenues resulting from significantly lower realized oil and natural gas sales prices and lower volume sold, impairment expenses in Canada in 2016 and lower after-tax gains on assets sold. These were partially offset by lower lease operating expenses and production taxes, lower depreciation expense, lower exploration costs and lower expenses for environmental costs. Corporate after-tax costs were $72.2 million in the 2016 period compared to after-tax costs of $53.0 million in the 2015 period as the current period had lower gains for the effects of foreign currency exchange and higher net interest costs, partially offset by lower administrative costs. Net loss in the first half of 2016 included income from discontinued operations of $0.7 million ($0.00 per diluted share) compared to a loss of $2.8 million ($0.02 per diluted share) in the 2015 period. Discontinued operations in both periods primarily consists of costs related to winding down of all operations in the U.K. The final components of the refining and marketing operations were sold at the end of the second quarter 2015.

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

Results of Operations (Contd.)

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)	2016	2015	2016	2015
Exploration and production				
United States	$ (65.7)	(16.5)	(131.4)	(110.4)
Canada	55.3	(32.2)	(31.9)	(70.7)
Malaysia	47.7	27.6	70.1	250.7
Other International	(5.1)	(30.1)	(31.2)	(102.1)
Total	$ 32.2	(51.2)	(124.4)	(32.5)

Second quarter 2016 vs. 2015

United States exploration and production operations reported a loss of $65.7 million in the second quarter of 2016 compared to a loss of $16.5 million in the 2015 quarter. Results were lower by $49.2 million in the 2016 quarter compared to the 2015 period as revenue in the U.S. fell $196.2 million in the current period due to both lower oil and natural gas realized sales prices and lower volumes sold. Lower supply costs and lower exploration expenses partially offset the decline in revenues. Lease operating expenses decreased by $24.1 million due to lower costs in Eagle Ford Shale and offshore Gulf of Mexico compared to same quarter in 2015 with most of the reduction due to the Company aggressively attacking its cost structure. Severance and ad valorem taxes in the 2016 quarter were $5.1 million lower than the 2015 period primarily due to weaker average commodity prices and lower volume sold. Depreciation expense decreased $50.1 million in 2016 compared to 2015 due to lower volume sold and lower unit rate in Eagle Ford Shale in the 2016 period. Exploration expenses were down $29.9 million in the second quarter of 2016 primarily related to lower dry hole costs of $18.5 million and lower undeveloped lease amortization compared to the 2015 quarter.

Operations in Canada had earnings of $55.3 million in the second quarter 2016 compared to a loss of $32.2 million in the 2015 quarter. Canadian results of operations improved by $87.5 million in the 2016 quarter. Results for conventional operations improved $20.9 million in 2016 due to lower production costs, higher natural gas volumes produced in the Tupper area of Western Canada, income tax benefits associated with divestiture of Montney midstream assets and no repeat of a tax charge related to a 2% increase in the statutory tax rate in Alberta in 2015, offset in part by lower average realized sales prices for crude oil and natural gas and lower oil volume sold. Lease operating expenses associated with conventional operations were $7.7 million lower in the 2016 quarter due to both lower costs and a weaker Canadian dollar exchange rate. Depreciation expense in conventional operations decreased by $13.5 million in the 2016 period due to lower unit rates, lower volume sold and a weaker Canadian dollar exchange rate. Synthetic operations earned $51.9 million in 2016 compared to a loss of $14.7 million in the 2015 period. The largest contributing factor to this 2016 improvement was a $71.7 million after-tax gain on sale of its non-operated interest in Syncrude completed at the end of the second quarter 2016. Normal synthetic operating results were $5.1 million lower in the 2016 period versus the 2015 quarter. Lower oil sales prices and lower volume sold in the 2016 period were partially offset by lower lease operating expense and no reoccurrence of the 2015 tax adjustment related to the aforementioned increase in the Alberta statutory tax rate. Lease operating expenses associated with synthetic operations were $11.7 million lower in the 2016 quarter due to lower variable costs and a weaker Canadian dollar exchange rate. Depreciation expense was $8.5 million lower in the current period due to lower volumes and a weaker Canadian dollar. Synthetic production volumes and lease operating expense were significantly impacted in 2016 by the facility being shut-in for 44 days of the quarter due to forest fires in the area.

Malaysia operations reported earnings of $47.7 million in the 2016 quarter compared to earnings of $27.6 million during the same period in 2015. Results improved $20.1 million in 2016 in Malaysia primarily due to lower lease operating expenses and lower depreciation expense, partially offset by lower commodity prices received and lower volumes sold in the 2016 period. Lease operating expenses decreased in the 2016 period by $27.5 million due to lower costs and lower volume sold compared to 2015. Depreciation expense was $78.1 million lower in 2016 compared to the 2015 quarter primarily due to lower unit rates following 2015 impairment charges at certain producing properties, and lower oil and natural gas volumes sold.

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

Second quarter 2016 vs. 2015 (Contd.)

Other international operations reported a loss of $5.1 million in the second quarter of 2016 compared to a loss of $30.1 million in the 2015 quarter. The $25.0 million improvement in the 2016 period was primarily related to a favorable adjustment of previously recorded exit costs associated with ceasing production operations in Republic of Congo in the current period versus a charge in the 2015 period for uncollectible receivables from partners in Republic of Congo.

Total hydrocarbon production averaged 168,642 barrels of oil equivalent per day in the 2016 second quarter, which represented a 16.5% decrease from the 201,952 barrels of oil equivalents per day produced in the 2015 quarter. Average crude oil and condensate production was 98,995 barrels per day in the second quarter of 2016 compared to 121,262 barrels per day in the second quarter of 2015. Crude oil production decreased 12,385 barrels in the Eagle Ford Shale area of South Texas in 2016 due to well decline associated with significantly less drilling in the last half of 2015 and early 2016 in response to lower prices. Heavy oil production from the Seal area in Western Canada was lower in 2016 primarily due to volumes shut-in associated with uneconomic wells and natural decline. Oil production offshore Eastern Canada was slightly higher during 2016 primarily due to better uptime at the Hibernia field. Synthetic oil production was 6,036 barrels per day lower in the 2016 period due to the facility being shut in for 44 days due to forest fires in the surrounding area. Lower oil production in 2016 in Malaysia was primarily attributable to less net oil volumes produced due to the sale of 10% of the Company's total interest in early 2015 coupled with natural decline. On a worldwide basis, the Company's crude oil and condensate prices averaged $44.42 per barrel in the second quarter 2016 compared to $56.49 per barrel in the 2015 period, a decline of 21% quarter to quarter. Total production of natural gas liquids (NGL) was 8,883 barrels per day in the 2016 second quarter compared to 9,779 barrels per day in the same 2015 period. The decrease in NGL production was primarily associated with lower natural gas volumes produced in the U.S. The average sales price for U.S. NGL was $11.33 per barrel in the 2016 quarter compared to $12.64 per barrel in 2015. Natural gas sales volumes averaged 365 million cubic feet per day in the second quarter 2016 compared to 425 million cubic feet per day in 2015. Natural gas sales volumes decreased in North America in 2016 due primarily to lower volumes produced offshore Gulf of Mexico but partially offset by higher volumes in the Tupper area of Western Canada. Natural gas sales volumes in Malaysia decreased in the 2016 period due to more downtime in the 2016 period. North American natural gas sales prices averaged $1.35 per thousand cubic feet (MCF) in the 2016 quarter, 44% below the $2.42 per MCF average in the same quarter of 2015. The average realized price for natural gas produced in the 2016 quarter at fields offshore Sarawak was $3.29

per MCF, compared to a price of $3.82 per MCF in the 2015 quarter.

Six Months 2016 vs. 2015

United States exploration and production operations reported a loss of $131.4 million in the first half of 2016 compared to a loss of $110.4 million in the 2015 period. The loss increased $21.0 million in 2016 compared to the 2015 period due to lower revenues partially offset by lower production costs and lower exploration expenses. Revenue in the U.S. fell $301.6 million in the period due to both lower oil and natural gas realized sales prices and lower volumes sold. Lease operating expenses decreased by $70.4 million due to lower costs in Eagle Ford Shale and offshore Gulf of Mexico compared to the same period in 2015, with most of the reduction due to the Company aggressively attacking its cost structure coupled with lower variable costs based on volumes produced. Severance and ad valorem taxes in the first half of 2016 were $13.0 million lower than the 2015 period primarily due to weaker average commodity prices and lower volume sold. Depreciation expense decreased $86.2 million in 2016 compared to 2015 due to lower unit rates in Eagle Ford Shale in the 2016 period and lower U.S. volume sold. Exploration expenses were down $86.1 million in the 2016 period primarily related to lower dry hole costs of $64.9 million and lower undeveloped lease amortization expense compared to the first half of 2015.

Operations in Canada had a loss of $31.9 million in the first half of 2016 compared to a loss of $70.7 million in the 2015 six months. Canadian results of operations improved by $38.8 million in the 2016 period. Results for conventional operations worsened by $27.7 million in 2016 due to impairment expense, lower average realized sales prices for crude oil and natural gas and lower oil volume sold. These were partially offset by higher natural gas volumes produced, lower production costs, no repeat of prior year charges for an environmental provision at the Seal heavy oil area, income tax benefits recognized on the sale of certain Montney midstream assets in 2016, and no repeat of a tax adjustment in 2015 for a 2% increase in the statutory tax rate in Alberta. Lease operating expenses associated with conventional operations were $15.6 million lower in the first six months of 2016 due to both lower costs and a weaker Canadian dollar exchange rate. Depreciation expense was $28.7 million lower in the 2016 period compared to 2015 due primarily to lower unit rates and mix of volume sold. Impairment expense was $95.1 million in 2016, as low oil prices led to a write down of heavy oil properties at Seal in Western

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

Six Months 2016 vs. 2015 (Contd.)

Canada and the Terra Nova field offshore East Coast Canada in the first quarter of the year. Synthetic operations generated $47.9 million in income in 2016 compared to a loss of $18.6 million in the same period of 2015. A $71.7 million after-tax gain on sale of the Company's non-operated interest in Syncrude completed at the end of the second quarter was the primary driver of the improvement. Normal operating results were $5.2 million lower in the 2016 period versus the 2015 quarter. Lower oil sales prices and lower volume sold in the 2016 period were partially offset by lower supply costs and no reoccurrence of the 2015 adjustment related to the aforementioned increase in the Alberta statutory tax rate. Lease operating expenses associated with synthetic operations were $17.6 million lower in the 2016 quarter due to lower variable costs and a weaker Canadian dollar exchange rate. Depreciation expense declined $8.9 million in the 2016 period due to lower unit rate and lower volume produced. Production volumes, lease operating expense and depreciation expense were significantly impacted by the facility being shut-in for 44 days of the quarter due to forest fires in the area.

Malaysia operations reported earnings of $70.1 million in the first half of 2016 compared to earnings of $250.7 million during the same period in 2015. Results were down $180.6 million in 2016 in Malaysia primarily due to a $218.8 million after-tax gain on sale of a 10% interest in Malaysian assets in the 2015 period. Revenue declined by 351.4 million driven by lower commodity prices received and lower volumes sold in the 2016 period, but this was partially offset by lower lease operating expenses and lower depreciation expense. Lease operating expenses decreased in the 2016 period by $40.7 million due to lower maintenance costs and cost cutting measures, and lower volume sold compared to 2015. Depreciation expense was $222.6 million lower in 2016 compared to the same period in 2015 primarily due to lower unit rates following 2015 impairment charges at certain producing properties and lower oil and natural gas volumes sold.

Other international operations reported a loss of $31.2 million in the first six months of 2016 compared to a loss of $102.1 million in the 2015 period. The 2016 period included lower dry hole costs of $23.9 million, with the higher 2015 costs primarily associated with unsuccessful wildcat drilling offshore Australia. Geological and geophysical costs were $12.6 million lower in the 2016 period, primarily due to less seismic data acquired in Australia. Other exploration expenses were $6.7 million lower in the current year, mostly attributable to the Company closing certain field offices beginning in late 2015 and aggressively attacking its cost structure. Other expenses were $21.0 million less in the 2016 period primarily related to an adjustment of previously recorded exit costs in the current period associated with ceasing production operations in Republic of Congo versus a charge in the 2015 period for uncollectible receivables from partners in Murphy West Africa.

Total worldwide production averaged 182,604 barrels of oil equivalent per day during the six months ended June 30, 2016, a decrease from 211,699 barrels of oil equivalent produced in the same period in 2015. Crude oil and condensate production in the first half of 2016 averaged 111,235 barrels per day compared to 130,778 barrels per day a year ago. Crude oil production decreased 9,933 barrels per day in the Eagle Ford Shale in 2016 due to well decline associated with significantly less drilling beginning in the last half of 2015 and continuing into 2016 in response to lower prices. Heavy oil production in Canada declined in 2016 in the Seal area of Western Canada primarily due to uneconomic well volumes shut-in caused by low sales prices, and natural decline. Synthetic oil production in Canada also was lower in 2016 due to impacts of maintenance work and downtime associated with forest fires in the surrounding area. Lower oil production in 2016 in Malaysia was primarily attributable to natural well decline. For the first six months of 2016, the Company’s sales price for crude oil and condensate averaged $38.78 per barrel, down from $51.26 per barrel in 2015. Total production of natural gas liquids was 9,058 barrels per day in the 2016 period compared to 10,094 barrels per day a year ago. The sales price for U.S. natural gas liquids averaged $9.80 per barrel in 2016 compared to $12.77 per barrel in 2015. Natural gas sales volumes decreased from 425 million cubic feet per day in 2015 to 374 million cubic feet per day in 2016. Natural gas sales volumes increased in North America due to higher gas production volumes in the Tupper area in Western Canada and Eagle Ford Shale area of South Texas, offset in part by lower gas volume in the Gulf of Mexico primarily in the Dalmatian field. The increase in North America was more than offset by lower production in Malaysia due to unplanned downtime in both Sarawak and Block K. The average sales price for North American natural gas in the first six months of 2016 was $1.45 per MCF, down from $2.44 per MCF realized in 2015. Natural gas production at fields offshore Sarawak was sold at an average realized price of $3.52 per MCF in 2016 compared to $4.53 per MCF in 2015.

Additional details about results of oil and gas operations are presented in the tables on pages 26 and 27.

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

Ex

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net crude oil and condensate produced – barrels per day	98,995	121,262	111,235	130,778
United States – Eagle Ford Shale	34,563	46,948	38,550	48,483
– Gulf of Mexico and other	12,564	12,263	13,331	12,519
Canada – light	950	91	540	110
– heavy	2,200	6,343	2,759	6,276
– offshore	7,217	6,043	8,020	7,702
– synthetic	3,093	9,129	9,326	11,394
Malaysia1 – Sarawak	13,944	14,167	13,490	15,951
– Block K	24,464	26,278	25,219	28,343
Net crude oil and condensate sold – barrels per day	96,918	114,178	108,054	131,706
United States – Eagle Ford Shale	34,563	46,948	38,550	48,483
– Gulf of Mexico and other	12,564	12,263	13,331	12,519
Canada – light	950	91	540	110
– heavy	2,200	6,343	2,759	6,276
– offshore	7,315	6,907	8,348	8,065
– synthetic	3,093	9,129	9,326	11,394
Malaysia1 – Sarawak	9,666	12,966	11,712	17,066
– Block K	26,567	19,531	23,488	27,793
Net natural gas liquids produced – barrels per day	8,883	9,779	9,058	10,094
United States – Eagle Ford Shale	6,751	7,579	6,988	7,517
– Gulf of Mexico and other	1,468	1,636	1,347	1,895
Canada	164	5	88	14
Malaysia1 – Sarawak	500	559	635	668
Net natural gas liquids sold – barrels per day	9,339	9,611	9,550	9,794
United States – Eagle Ford Shale	6,751	7,579	6,988	7,517
– Gulf of Mexico	1,468	1,636	1,347	1,895
Canada	164	5	88	14
Malaysia1 – Sarawak	956	391	1,127	368
Net natural gas sold – thousands of cubic feet per day	364,582	425,463	373,864	424,961

United States – Eagle Ford Shale	36,113	37,790	37,203	39,030
– Gulf of Mexico and other	16,779	54,093	20,094	55,563
Canada	204,753	195,159	207,288	193,133
Malaysia1 – Sarawak	96,057	110,816	97,155	111,431
– Block K	10,880	27,605	12,124	25,804
Total net hydrocarbons produced – equivalent barrels per day2	168,642	201,952	182,604	211,699
Total net hydrocarbons sold – equivalent barrels per day2	167,021	194,700	179,915	212,327

1 The Company sold a 10% interest in Malaysia properties on January 29, 2015. Production in this table includes production for these sold interests through the date of disposition.

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,		Six Months Ended June 30,	
	2016	2015	2016	2015
Weighted average sales prices				
Crude oil and condensate – dollars per barrel				
United States – Eagle Ford Shale	$ 43.95	55.66	38.93	49.55
– Gulf of Mexico	43.41	59.14	39.00	52.52
Canada – heavy	18.03	33.85	11.83	27.02
– offshore	44.51	60.35	36.82	55.51
– synthetic	45.78	60.88	35.58	51.27
Malaysia – Sarawak[2]	47.22	57.91	41.74	52.87
– Block K[2]	46.53	59.81	41.97	56.96
Natural gas liquids – dollars per barrel				
United States – Eagle Ford Shale	$ 11.21	12.15	9.65	12.22
– Gulf of Mexico	11.89	14.32	10.59	14.50
Canada[1]	30.18	21.62	29.38	22.31
Malaysia – Sarawak[2]	34.62	47.59	35.65	58.08
Natural gas – dollars per thousand cubic feet				
United States – Eagle Ford Shale	$ 1.38	2.23	1.43	2.39
– Gulf of Mexico	1.46	2.37	1.62	2.48
Canada[1]	1.33	2.47	1.44	2.44
Malaysia – Sarawak[2]	3.29	3.82	3.52	4.53
– Block K	0.23	0.23	0.25	0.24

1 U.S. dollar equivalent.

2 Prices are net of payments under 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, 2016 AND 2015

(Millions of dollars)	United States	Canada Conven-tional	Synthetic	Malaysia	Other	Total
Three Months Ended June 30, 2016						
Oil and gas sales and other operating revenues	$ 143.6	61.6	15.8	190.5	(0.1)	411.4
Lease operating expenses	54.5	25.0	31.8	45.2	–	156.5
Severance and ad valorem taxes	11.0	1.1	1.3	–	–	13.4
Depreciation, depletion and amortization	146.6	45.9	3.1	54.0	1.6	251.2
Accretion of asset retirement obligations	4.3	2.8	1.2	4.0	–	12.3
Exploration expenses						
Dry holes	(0.8)	–	–	4.5	10.7	14.4
Geological and geophysical	0.3	–	–	0.2	–	0.5
Other	1.0	0.1	–	–	6.2	7.3
	0.5	0.1	–	4.7	16.9	22.2
Undeveloped lease amortization	13.7	1.0	–	–	0.2	14.9
Total exploration expenses	14.2	1.1	–	4.7	17.1	37.1
Selling and general expenses	12.7	8.1	0.2	5.0	9.1	35.1
Other expenses (benefits)	(0.1)	1.6	–	0.9	(9.9)	(7.5)
Results of operations before taxes	(99.6)	(24.0)	(21.8)	76.7	(18.0)	(86.7)
Income tax provisions (benefits)	(33.9)	(27.4)	(73.7)	29.0	(12.9)	(118.9)
Results of operations (excluding corporate overhead and interest)	$ (65.7)	3.4	51.9	47.7	(5.1)	32.2
Three Months Ended June 30, 2015						
Oil and gas sales and other operating revenues	$ 339.8	102.2	50.7	244.5	–	737.2
Lease operating expenses	78.6	32.7	43.5	72.7	–	227.5
Severance and ad valorem taxes	16.1	1.3	1.7	–	–	19.1
Depreciation, depletion and amortization	196.7	59.4	11.6	132.1	1.6	401.4
Accretion of asset retirement obligations	4.9	1.7	1.4	3.7	–	11.7
Exploration expenses						

Dry holes	17.7	–	–	–	2.7	20.4
Geological and geophysical	3.6	–	–	1.3	1.8	6.7
Other	3.1	0.2	–	–	10.4	13.7
	24.4	0.2	–	1.3	14.9	40.8
Undeveloped lease amortization	19.7	4.2	–	–	0.3	24.2
Total exploration expenses	44.1	4.4	–	1.3	15.2	65.0
Selling and general expenses	22.9	6.5	0.2	0.5	14.4	44.5
Other expenses (benefits)	1.8	(0.1)	–	–	12.1	13.8
Results of operations before taxes	(25.3)	(3.7)	(7.7)	34.2	(43.3)	(45.8)
Income tax provisions (benefits)	(8.8)	13.8	7.0	6.6	(13.2)	5.4
Results of operations (excluding corporate overhead and interest)	$ (16.5)	(17.5)	(14.7)	27.6	(30.1)	(51.2)

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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, 2016 AND 2015

(Millions of dollars)	United States	Canada Conven-tional	Synthetic	Malaysia	Other	Total
Six Months Ended June 30, 2016						
Oil and gas sales and other operating revenues	$ 318.3	119.2	64.3	338.8	–	840.6
Lease operating expenses	110.0	42.7	69.8	93.1	–	315.6
Severance and ad valorem taxes	21.4	2.2	2.5	–	–	26.1
Depreciation, depletion and amortization	315.3	90.8	16.5	108.1	3.0	533.7
Accretion of asset retirement obligations	8.6	5.4	2.4	8.1	–	24.5
Impairment of assets	–	95.1	–	–	–	95.1
Exploration expenses						
Dry holes	(0.5)	–	–	4.1	10.7	14.3
Geological and geophysical	0.6	2.9	–	0.5	4.3	8.3
Other	2.1	0.4	–	–	13.5	16.0
	2.2	3.3	–	4.6	28.5	38.6
Undeveloped lease amortization	22.7	2.3	–	–	0.4	25.4
Total exploration expenses	24.9	5.6	–	4.6	28.9	64.0
Selling and general expenses	35.2	15.7	0.5	8.4	19.2	79.0
Other expenses (benefits)	0.1	–	–	0.9	(8.9)	(7.9)
Results of operations before taxes	(197.2)	(138.3)	(27.4)	115.6	(42.2)	(289.5)
Income tax provisions (benefits)	(65.8)	(58.5)	(75.3)	45.5	(11.0)	(165.1)
Results of operations (excluding corporate overhead and interest)	$ (131.4)	(79.8)	47.9	70.1	(31.2)	(124.4)
Six Months Ended June 30, 2015						
Oil and gas sales and other operating revenues	$ 619.9	199.3	105.9	690.2	–	1,615.3
Lease operating expenses	180.4	58.3	87.4	133.8	–	459.9

Severance and ad valorem taxes	34.4	2.7	2.8	–	–	39.9
Depreciation, depletion and amortization	401.5	119.5	25.4	330.7	3.1	880.2
Accretion of asset retirement obligations	9.7	3.4	2.8	7.6	–	23.5
Exploration expenses						
Dry holes	64.4	–	–	–	34.6	99.0
Geological and geophysical	5.3	–	–	1.3	16.9	23.5
Other	4.8	0.4	–	–	20.2	25.4
	74.5	0.4	–	1.3	71.7	147.9
Undeveloped lease amortization	36.5	8.4	–	–	0.9	45.8
Total exploration expenses	111.0	8.8	–	1.3	72.6	193.7
Selling and general expenses	45.3	13.3	0.4	1.2	29.1	89.3
Other expenses	7.5	43.9	–	–	12.1	63.5
Results of operations before taxes	(169.9)	(50.6)	(12.9)	215.6	(116.9)	(134.7)
Income tax provisions (benefits)	(59.5)	1.5	5.7	(35.1)	(14.8)	(102.2)
Results of operations (excluding corporate overhead and interest)	$ (110.4)	(52.1)	(18.6)	250.7	(102.1)	(32.5)

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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 cost of $29.3 million in the 2016 second quarter compared to a net cost of $37.8 million in the same 2015 quarter. The $8.5 million lower cost in the 2016 period is primarily due to higher benefits from foreign currency exchange and lower administrative costs, partially offset by higher net interest costs and lower tax benefits. An after-tax gain of $19.5 million occurred in 2016 on transactions denominated in foreign currencies, while the 2015 quarter had an after-tax gain of $1.3 million.

For the first half of 2016, corporate activities reflected net costs of $72.2 million compared to net costs of $53.0 million a year ago. The $19.2 million increase in net cost in the current year is primarily due to lower foreign currency exchange benefits and higher net interest cost. An after-tax gain of $21.3 million occurred in 2016 on transactions denominated in foreign currencies compared to an after-tax gain of $35.1 million a year ago.

Discontinued Operations

The Company has presented all operations in the U.K. as discontinued operations in its consolidated financial statements. In June 2015, the Company completed an agreement to sell the remaining U.K. downstream assets.

The after-tax results of the U.K. operations for the three-month and six-month periods ended June 30, 2016 and 2015 are reflected in the following table.

(Millions of dollars)		Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
U.K. refining and marketing	$	(1.7)	15.4	(0.1)	(2.6)
U.K. exploration and production		1.7	(0.2)	0.8	(0.2)
Income (loss) from discontinued operations	$	–	15.2	0.7	(2.8)

Financial Condition

Net cash provided by continuing operating activities was $113.4 million for the first six-months of 2016 compared to $715.2 million during the same period in 2015. The decline in cash provided by continuing operations activities in 2016 was primarily attributable to significantly lower realized sales prices for the Company's oil and gas production and lower volume sold during the current year, offset in part by lower lease operating expenses. Changes in noncash operating working capital from continuing operations used cash of $86.8 million during the first six-months of 2016, compared to generating cash of $107.2 million in 2015. The use of cash in 2016 included $261.8 million associated with pay-off of cancelled deepwater rig contracts that were previously charged to expense in 2015. Proceeds from sales of property and equipment generated cash of $1,153.3 million in 2016 compared to $423.1 million in 2015. The 2016 proceeds are mainly attributable to the sale of the Company's non-operated 5% interest in Syncrude Canada Ltd. ("Syncrude") for $739.1 million and the disposition of certain midstream assets in the Tupper area of Western Canada for $414.1 million. The prior year amount primarily related to proceeds received upon sale of a 10% interest in Malaysian assets. Other significant sources of cash included $701.4 million in the 2016 period and $663.3 million in 2015 from maturity of Canadian government securities that had maturity dates greater than 90 days at acquisition. The Company borrowed $823.0 million in the 2015 period to fund capital expenditures and repurchase company stock.

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

Financial Condition (Contd.)

The uses of cash for property additions and dry holes, which including amounts expensed, were $604.6 million and $1,433.6 million in the six-month period ended June 30, 2016 and 2015, respectively. Total cash dividends to shareholders amounted to $120.5 million in 2016 and $124.6 million in 2015. In the first six months of 2015, the Company expended $250.0 million to acquire 5,236,709 shares of Common stock. Also, the purchase of Canadian government securities with maturity dates greater than 90 days at acquisition used cash of $651.2 million in the 2016 period and $629.8 million in the 2015 period. The Company repaid debt in the amount of $600.0 million in the six-month period of 2016. The debt repayment was funded using proceeds from the sale of assets. The Company had no borrowings outstanding on its $2.0 billion revolving credit facility at June 30, 2016. The Company used $450.0 million of cash in the 2015 period to repay current maturities of long-term debt.

Total accrual basis capital expenditures were as follows:

	Six Months Ended June 30,	
(Millions of dollars)	2016	2015
Capital Expenditures		
Exploration and production	$ 442.9	1,119.5
Corporate	20.7	25.6
Total capital expenditures	$ 463.6	1,145.1

The reduction in capital expenditures in the exploration and production business in 2016 compared to 2015 was primarily attributable to lower development drilling in the Eagle Ford Shale area in the United States and offshore Malaysia and lower spending on exploration drilling in the Gulf of Mexico and other international operations. The 2016 capital expenditures included $206 million to fund acquisition of Kaybob Duvernay and liquids rich Montney properties in Canada.

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

	Six Months Ended June 30,	
(Millions of dollars)	2016	2015
Property additions and dry hole costs per cash flow statements	$ 604.6	1,433.6
Geophysical and other exploration expenses	24.3	48.9
Capital expenditure accrual changes and other	(165.3)	(337.4)
Total capital expenditures	$ 463.6	1,145.1

Working capital (total current assets less total current liabilities) at June 30, 2016 was $157.1 million, $383.3 million more than December 31, 2015, with the increase attributable to lower accounts payable for deepwater rig contract exit cost and other operating activities.

At June 30, 2016, long-term debt of $2,435.5 million had decreased by $605.1 million compared to December 31, 2015. Long-term debt was paid down in 2016 using part of the sales proceeds from Canadian asset disposition. A summary of capital employed at June 30, 2016 and December 31, 2015 follows.

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	June 30, 2016		December 31, 2015	
(Millions of dollars)	Amount	%	Amount	%
Capital employed				
Long-term debt	$ 2,435.5	32.0 %	$ 3,040.6	36.4 %
Stockholders' equity	5,171.7	68.0	5,306.7	63.6
Total capital employed	$ 7,607.2	100.0 %	$ 8,347.3	100.0 %

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

Financial Condition (Contd.)

Cash and invested cash are maintained in several operating locations outside the United States. At June 30, 2016, cash, cash equivalents and cash temporarily invested in Canadian government securities held outside the U.S. included U.S. dollar equivalents of approximately $188.7 million in Canada and $81.4 million in Malaysia. 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 are permitted 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 through a dividend to the U.S. parent.

Accounting and Other Matters

Leases

In February 2016, The Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) to increase transparency and comparability among companies by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous generally accepted accounting principles (GAAP) and this ASU is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. The new standard is effective for financial statements issued for annual periods beginning after December 15, 2018 and interim periods within those annual periods. Early adoption is permitted for all entities. The Company anticipates adopting this guidance in 2019 and is currently evaluating the standard and its impact on its consolidated financial statements and footnote disclosures.

Compensation-Stock Compensation

In March 2016, the FASB issued an ASU intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification within the statement of cash flows. The amendments in this ASU are effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early adoption is permitted for any entity in any interim period or annual period. The Company will adopt this guidance in 2017 and is currently evaluating the impact on its consolidated financial statements and footnote disclosures.

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), a comprehensive new revenue recognition standard for contracts with customers that will supersede most current revenue recognition requirements and industry-specific guidance. The codification was amended through additional ASUs and, as amended, requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company is required to adopt the new standard in the first quarter of 2018 using either the retrospective or cumulative effect transition method. The Company has not yet selected a transition method and is currently evaluating the standard and the impact on its consolidated financial statements and footnote disclosures.

Outlook

Average worldwide crude oil prices in July 2016 are similar to the average prices during the second quarter of 2016 with Brent and WTI trading at near parity. Non-OPEC crude oil production continues to slide, but total commercial inventories that remain at elevated levels will be slow to clear. Driven by strong seasonal power demand, North American natural gas prices improved in July 2016 relative to the second quarter of 2016 as the U.S commercial inventory excess to the prior year was trimmed by nearly 60% since the end of the withdrawal season in March. The Company expects its total oil and natural gas production to average 167,500 to 169,500 barrels of oil equivalent per day in the third quarter 2016. The Company currently anticipates total capital expenditures for the full year 2016 to be approximately $620 million, excluding the cost to acquire the Kaybob Duvernay and liquids rich Montney interests in Canada.

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

Outlook (Contd)

The Company will primarily fund its capital program and property acquisitions in 2016 using operating cash flow and proceeds from recent divestitures, but supplements funding where necessary using borrowings under available credit facilities. As of June 30, 2016, there were no funds borrowed under its revolving credit facility. The Company’s current 2016 outlook calls for no borrowings under its revolving credit agreement during the second of half of 2016. If oil and/or natural gas prices weaken, actual cash flow generated from operations could be reduced such that unanticipated borrowings might be required during the year to maintain funding of the Company’s ongoing development projects. The Company’s revolving credit facility matures in June 2017, and the Company currently expects to execute a new agreement prior to expiry of the existing facility. A new credit facility may include different terms compared to the existing facility.

The significant reduction in the sales prices of crude oil has caused the Company to reduce capital expenditures, including development drilling and completion operations in North America. The Company’s capital spending program in 2016 will be well below 2015 levels. The reduced level of capital expenditures, if it continues, could lead to lower production levels in future periods. A continuation of low oil and/or gas prices or further deterioration therein, could lead to negative future effects on the Company, which could include reductions in proved reserves, additional impairment charges, the necessity for further cost containment measures, higher debt levels, and a reconsideration of the level of dividends on its Common stock.

As of August 3, 2016 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	July – Dec. 2016	25,000 bbls/d	$50.67 per bbl.
U.S. Oil	West Texas Intermediate	Jan – Dec. 2017	7,000 bbls/d	$50.10 per bbl.
Canadian Natural Gas	TCPL–NOVA System	July – Dec. 2016	99 mmcf/d	C$3.00 per mcf
Canadian Natural Gas	TCPL–NOVA System	Jan. 2017 – Dec. 2020	59 mmcf/d	C$2.81 per mcf

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 Murphy's exploration programs, the Company's ability to maintain production rates and replace reserves, customer demand for Murphy's products, adverse foreign exchange movements, political and regulatory instability, adverse developments in the U.S. or global capital markets, credit markets or economies generally and uncontrollable natural hazards. For further discussion of risk factors, see Murphy's 2015 Annual Report on Form 10-K on file with the U.S. Securities and Exchange Commission and page 32 of this Form 10-Q report. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

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 J 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 transactions in place at June 30, 2016 covering certain future U.S. crude oil sales volumes in 2016 and 2017. A 10% increase in the respective benchmark price of these commodities would have decreased the recorded net asset associated with these derivative contracts by approximately $36.4 million, while a 10% decrease in the benchmark price would have increased the recorded net asset by a similar amount.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK (Contd.)

There were derivative foreign exchange contracts in place at June 30, 2016 to hedge the value of the U.S. dollar against the Canadian dollar for certain U.S. dollar receivables to be collected in April 2016. A 10% strengthening of the U.S. dollar against the Canadian dollar would have increased the recorded net liability associated with these contracts by approximately $0.5 million, while a 10% weakening of the U.S. dollar would have decreased the recorded net liability by approximately $0.6 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.

During the quarter ended June 30, 2016, the Company continued to implement a new global Enterprise Resource Planning (ERP) system, which will handle the business and financial processes within the company's operations and its corporate and administrative functions. The Company has modified its existing internal controls related to the ERP system implementation. While the Company believes that this new system and the related changes to internal controls will ultimately strengthen its internal controls over financial reporting, there are inherent risks in implementing a new ERP system and the Company will continue to evaluate and test control changes in order to provide certification as of its fiscal year ending December 31, 2016 on the effectiveness, in all material respects, of its internal controls over financial reporting.

During the quarter ended June 30, 2016, there were no other changes in the Company's internal control over financial reporting 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.

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 its 2015 Form 10-K filed on February 26, 2016. The Company has not identified any additional risk factors not previously disclosed in its 2015 Form 10-K report.

ITEM 6. EXHIBITS

The Exhibit Index on page 34 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/ KEITH CALDWELL
Keith Caldwell, Senior Vice President and Controller (Chief Accounting Officer and Duly Authorized Officer)

August 4, 2016

(Date)

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EXHIBIT INDEX

Exhibit No.	
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.