MURPHY OIL CORP /DE
Form 10-Q
November 02, 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 September 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 September 30, 2016 was 172,200,075.

MURPHY OIL CORPORATION

TABLE OF CONTENTS

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED BALANCE SHEETS (unaudited)

(Thousands of dollars)

	September 30, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 753,093	283,183
Canadian government securities with maturities greater than 90 days at the date of acquisition	117,938	173,288
Accounts receivable, less allowance for doubtful accounts of $1,605 in 2016 and 2015	400,532	522,672
Inventories, at lower of cost or market		
Crude oil	11,196	25,583
Materials and supplies	151,107	141,205
Prepaid expenses	90,401	212,962
Deferred income taxes	50,879	51,183
Assets held for sale	29,978	38,340
Total current assets	1,605,124	1,448,416
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $12,425,414 in 2016 and $11,924,193 in 2015	8,440,336	9,818,365
Deferred charges and other assets	348,555	227,031
Total assets	$ 10,394,015	11,493,812
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 20,444	18,881
Accounts payable and accrued liabilities	876,664	1,643,632
Income taxes payable	13,817	4,819
Liabilities associated with assets held for sale	3,276	7,297
Total current liabilities	914,201	1,674,629
Long-term debt, including capital lease obligation	2,973,888	3,040,594
Deferred income taxes	50,244	239,811
Asset retirement obligations	748,576	793,474

Deferred credits and other liabilities	621,518	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	921,675	910,074
Retained earnings	5,836,567	6,212,201
Accumulated other comprehensive loss	(571,031)	(704,542)
Treasury stock, 22,855,649 shares of Common Stock in 2016 and 23,021,013 shares of Common Stock in 2015, at cost	(1,296,679)	(1,306,061)
Total stockholders’ equity	5,085,588	5,306,728
Total liabilities and stockholders’ equity	$ 10,394,015	11,493,812

See Notes to Consolidated Financial Statements, page 7.

The Exhibit Index is on page 35.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF OPERATIONS (unaudited)

(Thousands of dollars, except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
REVENUES				
Sales and other operating revenues	$ 486,276	665,589	1,326,587	2,133,360
Gain (loss) on sale of assets	(730)	60	3,101	154,183
Interest and other income	14,987	49,300	38,602	87,443
Total revenues	500,533	714,949	1,368,290	2,374,986
COSTS AND EXPENSES				
Lease operating expenses	119,663	183,826	435,296	643,736
Severance and ad valorem taxes	9,592	14,265	35,668	54,099
Exploration expenses, including undeveloped lease amortization	19,866	58,149	83,910	251,842
Selling and general expenses	55,523	71,791	196,143	237,934
Depreciation, depletion and amortization	255,900	433,706	797,288	1,318,123
Impairment of assets	–	2,300,974	95,088	2,300,974
Accretion of asset retirement obligations	11,043	11,918	35,514	35,437
Interest expense	40,088	32,009	107,207	91,945
Interest capitalized	(869)	(1,864)	(3,318)	(5,072)
Other expense (benefit)	6,486	18,192	(1,446)	81,804
Total costs and expenses	517,292	3,122,966	1,781,350	5,010,822
Loss from continuing operations before income taxes	(16,759)	(2,408,017)	(413,060)	(2,635,836)
Income tax benefit	(2,176)	(820,935)	(201,897)	(963,298)
Loss from continuing operations	(14,583)	(1,587,082)	(211,163)	(1,672,538)
Loss from discontinued operations, net of income taxes	(1,593)	(8,344)	(885)	(11,163)
NET LOSS	$ (16,176)	(1,595,426)	(212,048)	(1,683,701)
PER COMMON SHARE – BASIC				
Loss from continuing operations	$ (0.08)	(9.22)	(1.23)	(9.55)
Loss from discontinued operations	(0.01)	(0.04)	(0.01)	(0.07)
Net loss	$ (0.09)	(9.26)	(1.24)	(9.62)
PER COMMON SHARE – DILUTED				
Loss from continuing operations	$ (0.08)	(9.22)	(1.23)	(9.55)
Loss from discontinued operations	(0.01)	(0.04)	(0.01)	(0.07)
Net loss	$ (0.09)	(9.26)	(1.24)	(9.62)
Average Common shares outstanding				

Basic	172,199,350	172,205,433	172,164,683	175,047,295
Diluted	172,199,350	172,205,433	172,164,683	175,047,295

See Notes to Consolidated Financial Statements, page 7.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (unaudited)

(Thousands of dollars)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net loss	$ (16,176)	(1,595,426)	(212,048)	(1,683,701)
Other comprehensive income (loss), net of tax				
Net gain (loss) from foreign currency translation	(37,369)	(195,440)	124,522	(462,054)
Retirement and postretirement benefit plans	2,515	3,116	7,544	9,105
Deferred loss on interest rate hedges reclassified to interest expense	482	482	1,445	1,445
Other comprehensive income (loss)	(34,372)	(191,842)	133,511	(451,504)
COMPREHENSIVE LOSS	$ (50,548)	(1,787,268)	(78,537)	(2,135,205)

See Notes to Consolidated Financial Statements, page 7.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Thousands of dollars)

	Nine Months Ended September 30,		
	2016		2015
OPERATING ACTIVITIES			
Net loss	$ (212,048)		(1,683,701)
Adjustments to reconcile net loss to net cash provided by continuing operations activities:			
Loss from discontinued operations	885		11,163
Depreciation, depletion and amortization	797,288		1,318,123
Impairment of assets	95,088		2,300,974
Amortization of deferred major repair costs	3,794		5,450
Dry hole costs	15,226		120,459
Amortization of undeveloped leases	35,828		62,331
Accretion of asset retirement obligations	35,514		35,437
Deferred and noncurrent income tax benefits	(345,157)		(975,120)
Pretax gains from disposition of assets	(3,101)		(154,183)
Net (increase) decrease in noncash operating working capital	(152,618)	1	97,026
Other operating activities, net	9,651		(41,431)
Net cash provided by continuing operations activities	280,350		1,096,528
INVESTING ACTIVITIES			
Property additions and dry hole costs	(781,668)	2	(1,975,069)
Proceeds from sales of property, plant and equipment	1,154,623		423,842
Purchase of investment securities3	(651,218)		(865,251)
Proceeds from maturity of investment securities3	712,863		852,394
Other investing activities, net	(7,229)		(19,538)
Net cash provided (required) by investing activities	427,371		(1,583,622)
FINANCING ACTIVITIES			
Borrowings of debt	541,444		885,000
Repayments of debt	(600,000)		(450,000)
Capital lease obligation payments	(7,808)		(7,156)
Purchase of treasury stock	–		(250,000)
Withholding tax on stock-based incentive awards	(1,138)		(8,976)
Issue cost of debt facility	(13,971)		–
Cash dividends paid	(163,586)		(184,789)
Other financing activities, net	(20)		(153)
Net cash required by financing activities	(245,079)		(16,074)
CASH FLOWS FROM DISCONTINUED OPERATIONS			
Operating activities	2,830		(4,866)
Investing activities	–		5,343
Changes in cash included in current assets held for sale	(2,830)		179,774

Net increase in cash and cash equivalents of discontinued operations	–	180,251
Effect of exchange rate changes on cash and cash equivalents	7,268	8,276
Net increase (decrease) in cash and cash equivalents	469,910	(314,641)
Cash and cash equivalents at January 1	283,183	1,193,308
Cash and cash equivalents at September 30	$ 753,093	878,667

12016 balance includes payments for deepwater rig contract exit of $266.6 million.

2Includes costs of $206.7 million associated with acquisition of Kaybob Duvernay and Placid Montney.

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

See Notes to Consolidated Financial Statements, page 7.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (unaudited)

(Thousands of dollars)

	Nine Months Ended September 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 September 30, 2016 and September 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	–	(73)
Restricted stock transactions and other	(10,078)	(38,260)
Stock-based compensation	21,918	33,925
Other	(239)	(92)
Balance at end of period	921,675	902,241
Retained Earnings		
Balance at beginning of period	6,212,201	8,728,032
Net loss for the period	(212,048)	(1,683,701)
Cash dividends	(163,586)	(184,789)
Balance at end of period	5,836,567	6,859,542
Accumulated Other Comprehensive Loss		
Balance at beginning of period	(704,542)	(170,255)
Foreign currency translation gain (loss), net of income taxes	124,522	(462,054)
Retirement and postretirement benefit plans, net of income taxes	7,544	9,105
Deferred loss on interest rate hedges reclassified to interest expense, net of income taxes	1,445	1,445
Balance at end of period	(571,031)	(621,759)
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	389	322
Awarded restricted stock, net of forfeitures	8,993	29,176
Balance at end of period – 22,855,649 shares of Common Stock in 2016 and 22,303,782 shares of Common Stock in 2015, at cost	(1,296,679)	(1,306,626)
Total Stockholders' Equity	$ 5,085,588	6,028,454

See Notes to Consolidated Financial Statements, page 7.

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 September 30, 2016 and December 31, 2015, and the results of operations, cash flows and changes in stockholders' equity for the interim periods ended September 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 nine-month period ended September 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 September 30, 2016, the Company had total capitalized exploratory well costs pending the determination of proved reserves of $128.2 million. The following table reflects the net changes in capitalized exploratory well costs during the

nine-month periods ended September 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	847	89,197
Other adjustments	(3,205)	–
Balance at September 30	$ 128,156	209,652

7

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.

	September 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	$ 10,563	2	2	$ 52,249	5	3
One to two years	53,101	3	3	32,192	2	1
Two to three years	31,627	2	–	27,842	2	–
Three years or more	32,865	4	–	97,369	4	2
	$ 128,156	11	5	$ 209,652	13	6

Of the $117.6 million of exploratory well costs capitalized more than one year at September 30, 2016, $64.5 million is in Brunei, $31.4 million is in Vietnam and $21.7 million is in Malaysia. In all geographical areas, either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion.

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 has amortized $3.4 million of the deferred gain during 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 nine-month period ended September 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 third quarter 2015, declines in future oil and gas prices provided indications of possible impairments in certain of the Company’s producing properties. As a result of management’s assessments, during the third quarter of 2015, the Company recognized a pretax noncash impairment charge of approximately $2.3 billion to reduce the carrying value of certain producing properties in the Gulf of Mexico, Western Canada and Malaysia to their estimated fair value. 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

During 2015, the Company completed the second phase of the sale of 30% 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 $218.8 million on the sale of the final 10% portion of the total 30% sold.

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. The 2015 nine-month period includes an adjustment to the impairment recognized as a result of the final sale of the U.K. downstream assets.

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

	Three Months Ended September 30,			Nine Months Ended September 30,	
(Thousands of dollars)		2016	2015	2016	2015
Revenues (costs)	$	(1,345)	(1,342)	(510)	381,154
Loss before income taxes	$	(1,593)	(8,366)	(885)	(8,029)
Income tax (benefit) expense		–	(22)	–	3,134
Loss from discontinued operations	$	(1,593)	(8,344)	(885)	(11,163)

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 September 30, 2016 and December 31, 2015.

(Thousands of dollars)	September 30, 2016	December 31, 2015
Current assets		
Cash	$ 5,097	7,927
Accounts receivable	9,001	12,037
Other	15,880	18,376
Total current assets held for sale	$ 29,978	38,340
Current liabilities		
Accounts payable	$ 915	2,433
Accrued compensation and severance	–	2,179
Refinery decommissioning cost	2,361	2,685
Total current liabilities associated with assets held for sale	$ 3,276	7,297

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note D – Financing Arrangements and Debt

In August 2016 the Company reduced its existing $2.0 billion unsecured revolving credit facility (“2011 facility”) to $630 million and entered into a separate $1.2 billion senior unsecured guaranteed credit facility (“2016 facility”) with a major banking consortium that expires in August 2019. Facility fees of 0.5% are charged annually on the full $1.2 billion commitment. The Company incurred transaction costs of approximately $14.0 million to place the 2016 facility which are included in financing activities in the Consolidated Statement of Cash Flows. At September 30, 2016, the Company had no outstanding borrowings under either credit facility, however, there was approximately $88 million of issued letters of credit under the 2016 facility. The 2016 facility is unsecured, with guarantees from certain domestic and foreign subsidiaries. Should the Company make substantial asset sales, the facility size would be automatically reduced to a minimum of $1.0 billion. Borrowings under the 2016 facility are subject to varying interest rates ranging from LIBOR plus 250 basis points to LIBOR plus 450 basis points. The terms of the 2016 facility include covenants that impose certain restrictions on the Company. These financial covenants include a minimum adjusted EBITDAX of 2.5 times consolidated interest expense, consolidated debt not to exceed 3.75 times adjusted EBITDAX and minimum liquidity from U.S. and Canadian entities equal to or greater than $500 million. Also beginning March 31, 2017, if the Company’s total leverage ratio exceeds 3.25 times the Company’s trailing twelve month consolidated adjusted EBITDAX, as defined in the 2016 facility, the facility will become secured, subject to limitations set forth in the Company’s existing notes. The existing unsecured 2011 facility, which expires in June 2017, includes a financial covenant under which the Company may not have total debt in excess of 60% of its total capital employed (debt borrowed plus stockholders’ equity). As of September 30, 2016, the Company was in compliance with all financial covenants contained in both credit facilities. 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.

In August 2016, the Company sold $550 million of new notes that bear interest at the rate of 6.875% and mature on August 15, 2024. The new notes pay interest semi-annually on February 15 and August 15 of each year. The initial interest payment is to be made on February 15, 2017. The proceeds of the $550 million notes were used for general corporate purposes.

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 September 2028. Current maturities and long-term debt on the Consolidated Balance Sheet included $20.4 million and $202.7 million, respectively, associated with this lease at September 30, 2016.

Note E – Cash Flow Disclosures

Additional disclosures regarding cash flow activities are provided below.

(Thousands of dollars)	Nine Months Ended September 30, 2016	2015
Net (increase) decrease in operating working capital other than cash and cash equivalents:		
Decrease in accounts receivable	$ 75,841	389,413
Increase in inventories	(15,768)	(16,607)
Decrease (increase) in prepaid expenses	122,399	(87,051)
Decrease in deferred income tax assets	720	4,863
Decrease in accounts payable and accrued liabilities	(376,310)	(134,458)
Increase (decrease) in current income tax liabilities	40,500	(59,134)
Net (increase) decrease in noncash operating working capital	$ (152,618)	97,026
Supplementary disclosures:		
Cash income taxes paid (refunded), net	$ (3,911)	111,897
Interest paid, net of amounts capitalized	52,287	60,766
Non-cash investing activities:		
Asset retirement costs capitalized	$ 13,959	55,258
Decrease in capital expenditure accrual	179,203	374,720

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 nine-month periods ended September 30, 2016 and 2015.

	Three Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2016	2015	2016	2015
Service cost	$ 2,610	5,898	674	826
Interest cost	5,913	8,972	1,109	1,192
Expected return on plan assets	(6,626)	(10,471)	–	–
Amortization of prior service cost	323	187	(21)	(21)
Amortization of transitional asset	–	402	2	2
Recognized actuarial loss	3,617	3,885	38	193
Net periodic benefit expense	$ 5,837	8,873	1,802	2,192
	Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2016	2015	2016	2015
Service cost	$ 8,533	15,751	2,022	2,482
Interest cost	20,386	24,893	3,324	3,576
Expected return on plan assets	(21,709)	(27,882)	–	–
Amortization of prior service cost	963	580	(62)	(62)
Amortization of transitional asset	–	947	4	5
Recognized actuarial loss	10,864	11,667	113	578
	19,037	25,956	5,401	6,579

Special termination benefits	–	8,606	(19)	–
Curtailments	822	306	–	–
Net periodic benefit expense	$ 19,859	34,868	5,382	6,579

Curtailment expense for the nine months ended September 30, 2016 shown in the table above, relates to restructuring activities in the U.S. undertaken by the Company in the first quarter 2016. Termination and curtailment expenses for the nine months ended September 30, 2015 relate to restructuring activities in the U.S. undertaken by the Company in the second quarter 2015. During the nine-month period ended September 30, 2016, the Company made contributions of $10.0 million to its defined benefit pension and postretirement benefit plans. Remaining required funding in 2016 for the Company's defined benefit pension and postretirement benefit plans is anticipated to be $2.9 million.

Note G – Incentive Plans

The costs resulting from all share-based payment transactions are recognized as an expense in the Consolidated Statements of Operations 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 417,500 time-based RSU in February and April 2016. 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 values of time-based RSU was estimated based on the fair market value of the Company's stock on the date of grant, which ranged from $17.57 to 24.075 per share. Additionally, the Committee granted 708,200 SAR and 507,470 units of cash-settled RSU (RSU-C) to certain employees in 2016. 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 2016, 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.

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

(Thousands of dollars)	Nine Months Ended September 30, 2016	2015
Compensation charged against income before tax benefit	$ 35,948	30,722
Related income tax benefit recognized	11,796	9,046

12

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note H – Earnings per Share

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

three-month and nine-month periods ended September 30, 2016 and 2015. The following table reconciles the weighted-average shares outstanding used for these computations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Weighted-average shares)	2016	2015	2016	2015
Basic method	172,199,350	172,205,433	172,164,683	175,047,295
Dilutive stock options*	–	–	–	–
Diluted method	172,199,350	172,205,433	172,164,683	175,047,295

*Due to a net loss recognized by the Company for the three-month and nine-month periods ended September 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Antidilutive stock options excluded from diluted shares	5,884,201	5,807,453	5,822,036	5,770,731
Weighted average price of these options	$ 49.00	53.13	49.82	53.25

Note I – Income Taxes

The Company’s effective income tax rate is calculated as the amount of income tax expense (benefit) divided by income (loss) before income taxes. For the three-month and nine-month periods in 2016 and 2015, the Company’s effective income tax rates were as follows:

	2016	2015
Three months ended September 30	13.0%	34.1%
Nine months ended September 30	48.9%	36.6%

The effective tax rates for most periods differ from 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 the three-month period ended September 30, 2016 was less than the U.S. statutory tax rate primarily due to expenses in foreign jurisdictions for which no tax benefits were recognized. The effective tax rate for the nine-month period ended September 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 September 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 nine-month period ended September 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 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 September 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.

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 September 30, 2016 and 2015. The impact from marking to market these commodity derivative contracts increased the loss before income taxes by $3.9 million for the nine-month period ended September 30, 2016 and reduced the loss before income taxes by $7.4 million for the nine-month period ended September 30, 2015.

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

At September 30, 2016	Volumes (barrels per day)	Swap Prices
October – December 2016	25,000	$50.67 per barrel
January – December 2017	16,000	$50.34 per barrel
At September 30, 2015		
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 September 30, 2016 and 2015 short-term derivative instruments were outstanding in Canada for approximately $25.2 million and $6.2 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 nine-month periods ended September 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 September 30, 2016 and December 31, 2015, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

	September 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	$ 192	Accounts receivable	$ 89,358
Foreign exchange	Accounts receivable	142	Accounts payable	(29)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

For the three-month and nine-month periods ended September 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 September 30,		Nine Months Ended September 30,	
(Thousands of dollars) Type of Derivative Contract	Statement of Operations Location	2016	2015	2016	2015
Commodity	Sales and other operating revenues	$ 11,871	39,392	(22,678)	46,811
Foreign exchange	Interest and other income	143	33	26,929	47
		$ 12,014	39,425	4,251	46,858

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 nine-month periods ended September 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 September 30, 2016 was $10.8 million, which was recorded, net of income taxes of $5.8 million, in Accumulated Other Comprehensive Loss in the Consolidated Balance Sheet. The Company expects to charge approximately $0.7 million of this deferred loss to Interest expense in the Consolidated Statement of Operations during the remaining three 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 September 30, 2016 and December 31, 2015 are presented in the following table.

	September 30, 2016				December 31, 2015			
(Thousands of dollars)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Foreign currency exchange derivative contracts	$ –	142	–	142	–	–	–	–
Commodity derivative contracts	–	192	–	192	–	89,358	–	89,358
	$ –	334	–	334	–	89,358	–	89,358
Liabilities:								
Nonqualified employee savings plans	$ 13,637	–	–	13,637	12,971	–	–	12,971
Foreign currency exchange derivative contracts	–	–	–	–	–	29	–	29
	$ 13,637	–	–	13,637	12,971	29	–	13,000

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 September 30, 2016 and December 31, 2015.

Fair Values – Nonrecurring

As a result of significantly lower commodity prices during the nine-month periods ended September 30, 2016 and 2015, the Company recognized $95.1 million and $2.3 billion, respectively, in pretax noncash impairment charges related to producing properties. The fair value information associated with these impaired properties is presented in the following tables.

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

September 30, 2015

Total

(Thousands of dollars)	Fair Value Level 1	Level 2	Level 3	Net Book Value Prior to Impairment	Pretax (Noncash) Impairment Loss
Assets:					
Impaired proved properties					
Gulf of Mexico	$ –	–	216,602	361,402	144,800
Western Canada	–	–	23,526	707,100	683,574
Malaysia	–	–	1,208,900	2,681,500	1,472,600
	$ –	–	1,449,028	3,750,002	2,300,974

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note K – Accumulated Other Comprehensive Loss

The components of Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets at December 31, 2015 and September 30, 2016 and the changes during the nine-month period ended September 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	124,522	(3)	–	124,519
Reclassifications to income	–	7,547 [2]	1,445 [3]	8,992
Net other comprehensive income	124,522	7,544	1,445	133,511
Balance at September 30, 2016	$ (388,482)	(171,716)	(10,833)	(571,031)

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

[2] Reclassifications before taxes of $11,602 for the nine-month period ended September 30, 2016 are included in the computation of net periodic benefit expense. See Note G for additional information. Related income taxes of $4,055 for the nine-month period ended September 30, 2016 are included in Income tax expense.

[3] Reclassifications before taxes of $2,222 for the nine-month period ended September 30, 2016 are included in Interest expense. Related income taxes of $777 for the nine-month period ended September 30, 2016 are included in Income tax expense.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note L – Environmental and Other Contingencies(Contd.)

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 effect 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 $32.8 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 September 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.

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 thee months of 2016 of approximately 99 million cubic feet per day (MMCFD) at C$3.00 per MCF, 79 MMCFD at C$2.83 per MCF from January 2017 to December 2017 and 59 MMCFD at C$2.81 per MCF from January 2018 through December 2020. In October 2016, the Company entered into an additional 20 MMCFD of natural gas sales contracts for the January 2017 through December 2020 period at C$3.12 per MCF. These natural gas contracts have been accounted for as normal sales for accounting purposes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note N – Business Segments

(Millions of dollars)	Total Assets at September 30, 2016	Three Months Ended September 30, 2016 External Revenues	Three Months Ended September 30, 2016 Income (Loss)	Three Months Ended September 30, 2015 External Revenues	Three Months Ended September 30, 2015 Income (Loss)
Exploration and production*					
United States	$ 5,448.9	201.8	(27.1)	335.1	(107.8)
Canada	1,557.3	80.9	(4.8)	123.2	(507.0)
Malaysia	2,186.1	202.7	65.0	207.3	(952.7)
Other	120.2	0.2	(8.1)	–	(28.6)
Total exploration and production	9,312.5	485.6	25.0	665.6	(1,596.1)
Corporate	1,051.5	14.9	(39.6)	49.3	9.0
Assets/revenue/income (loss) from continuing operations	10,364.0	500.5	(14.6)	714.9	(1,587.1)
Discontinued operations, net of tax	30.0	–	(1.6)	–	(8.3)
Total	$ 10,394.0	500.5	(16.2)	714.9	(1,595.4)

(Millions of dollars)		Nine Months Ended September 30, 2016 External Revenues	Nine Months Ended September 30, 2016 Income (Loss)	Nine Months Ended September 30, 2015 External Revenues	Nine Months Ended September 30, 2015 Income (Loss)
Exploration and production*					
United States	$	520.2	(158.5)	955.0	(218.1)
Canada		264.4	(36.9)	428.4	(577.8)
Malaysia		541.4	135.1	897.6	(701.9)
Other		0.2	(39.2)	–	(130.7)
Total exploration and production		1,326.2	(99.5)	2,281.0	(1,628.5)
Corporate		42.1	(111.7)	94.0	(44.0)
Revenue/income (loss) from continuing operations		1,368.3	(211.2)	2,375.0	(1,672.5)
Discontinued operations, net of tax		–	(0.8)	–	(11.2)
Total	$	1,368.3	(212.0)	2,375.0	(1,683.7)

*Additional details about results of oil and gas operations are presented in the tables on pages 27 and 28.

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 an ASU to establish 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.

Statement of Cash Flows

In August 2016, the FASB issued Accounting Standards Update (“ASU”) No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (“ASU 2016-15)”). ASU 2016-15 reduces diversity in practice in how certain transactions are classified in the statement of cash flows. The amendments in ASU 2016-15 provide guidance on specific cash flow issues including debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, and distributions received from equity method investees. ASU 2016-15 is effective for annual and interim periods beginning after December 5, 2017. The Company is currently assessing the potential impact of ASU 2016-15 on its consolidated financial statements.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS

Overall Review

During 2016, worldwide benchmark oil and natural gas prices have been approximately 20% below average comparable benchmark prices during the 2015 period. These lower oil and natural gas prices coupled with lower net hydrocarbons sold and a property impairment in the 2016 period have led the Company to incur losses from operations in the first nine months of 2016. Although the Company has been lowering 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 results by type of business is presented below.

	Income (Loss) Three Months Ended September 30,		Nine Months Ended September 30,	
(Millions of dollars)	2016	2015	2016	2015
Exploration and production	$ 25.0	(1,596.1)	(99.5)	(1,628.5)
Corporate and other	(39.6)	9.0	(111.7)	(44.0)
Loss from continuing operations	(14.6)	(1,587.1)	(211.2)	(1,672.5)
Discontinued operations	(1.6)	(8.3)	(0.8)	(11.2)
Net loss	$ (16.2)	(1,595.4)	(212.0)	(1,683.7)

Murphy's net loss in the third quarter of 2016 was $16.2 million ($0.09 per diluted share) compared to net loss of $1,595.4 million ($9.26 per diluted share) in the third quarter of 2015. Loss from continuing operations was $14.6 million ($0.08 per diluted share) in the third quarter 2016 compared to a loss of $1,587.1 million ($9.22 per diluted share) in the 2015 quarter. In the 2016 third quarter, the Company's exploration and production continuing operations earned $25.0 million compared to a loss of $1,596.1 million in the 2015 quarter. The net loss in the 2016 quarter was favorably impacted by no asset impairments compared to the 2015 period, lower lease operating expenses and depreciation expense, lower exploration costs and lower selling and general expenses. These were offset in part by lower revenues primarily due to significantly weaker realized oil and natural gas sales prices and lower volumes sold. The corporate function had after-tax costs of $39.6 million in the 2016 third quarter compared to after-tax income of $9.0 million in the 2015 period with the unfavorable variance in the current period mostly due to lower benefits from foreign exchange effects and higher net interest costs offset in part by lower administrative costs. The 2016 third quarter included $1.6 million loss ($0.01 per diluted share) from discontinued operations compared to a loss of $8.3 million ($0.04 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.

For the first nine months of 2016, net loss totaled $212.0 million ($1.24 per diluted share) compared to a net loss of $1,683.7 million ($9.62 per diluted share) for the same period in 2015. Continuing operations had a loss of $211.2 million ($1.23 per diluted share) in the first nine months of 2016, compared to a loss of $1,672.5 million ($9.55 per diluted share) in the same period of 2015. In the first nine months of 2016, the Company’s exploration and production operations incurred a loss of $99.5 million compared to a loss of $1,628.5 million in the same period of 2015. Exploration and production loss in 2016 was lower than the 2015 period primarily due to lower impairment expenses, lower lease operating expenses and depreciation expense, lower exploration expenses, and lower selling and general expenses. These improvements were partially offset by lower revenues resulting from lower realized oil and natural gas sales prices and lower volumes sold, losses on open crude oil contract positions in the 2016 period versus gains in the 2015 period and lower gains on assets sold. Corporate after-tax costs were $111.7 million in the 2016 period compared to after-tax costs of $44.0 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 nine months of 2016 included a loss from discontinued operations of $0.8 million ($0.01 per diluted share) compared to a loss of $11.2 million ($0.07 per diluted share) in the 2015 period. Discontinued operations in in the 2015 period primarily consisted of costs related to winding down of all operations in the U.K., of which the final components of the refining and marketing operations were sold in 2015.

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 September 30,		Nine Months Ended September 30,	
(Millions of dollars)	2016	2015	2016	2015
Exploration and production				
United States	$ (27.1)	(107.8)	(158.5)	(218.1)
Canada	(4.8)	(507.0)	(36.9)	(577.8)
Malaysia	65.0	(952.7)	135.1	(701.9)
Other	(8.1)	(28.6)	(39.2)	(130.7)
Total	$ 25.0	(1,596.1)	(99.5)	(1,628.5)

Third quarter 2016 vs. 2015

United States exploration and production operations reported a loss of $27.1 million in the third quarter of 2016 compared to a loss of $107.8 million in the 2015 quarter. Results improved by $80.7 million in the 2016 quarter compared to the 2015 period primarily due to no impairment expenses in the 2016 period. Revenues declined $133.3 million in the current period primarily due to lower oil and natural gas realized sales prices and lower volumes sold together with unfavorable mark-to-market results relating to open crude oil contract positions. The decline in revenue was partially offset by lower supply costs and lower exploration expenses. Lease operating expenses decreased by $7.3 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 lowering its cost structure offset in part by higher costs of workovers. Severance and ad valorem taxes in the 2016 quarter were $3.6 million lower than the 2015 period primarily due to weaker average commodity prices and lower volume sold. Depreciation expense decreased $79.7 million in 2016 compared to 2015 due to lower volume sold and lower unit rates. Unit rates improved in Eagle Ford Shale in the 2016 period due to lower drilling costs and migration of reserves, while the offshore Gulf of Mexico unit rates improved primarily due to impairments reported in the prior year. Exploration expenses were down $14.1 million in the third quarter of 2016 primarily related to lower dry hole costs of $9.4 million and lower undeveloped lease amortization compared to the 2015 quarter.

Operations in Canada had a loss of $4.8 million in the third quarter 2016 compared to losses of $507.0 million in the 2015 quarter, an improvement of $502.2 quarter over quarter. Results for conventional operations improved $498.0 million in 2016 primarily due to impairments in the 2015 period that did not repeat in 2016. Revenues improved primarily due to higher volume sold from its offshore assets offset by lower oil and natural gas sales prices realized in the other conventional producing areas. Depreciation expense was lower by $5.1 million primarily due to the impairment of its heavy oil properties during 2015 but lease operating expense increased $8.1 million due to higher natural gas volumes produced in the Tupper area of Western Canada and higher natural gas processing costs together with a slightly stronger Canadian dollar exchange rate. The Company sold its non-operated interest in Syncrude at the end of the second quarter 2016.

Malaysia operations reported earnings of $65.0 million in the 2016 quarter compared to losses of $952.7 million during the same period in 2015. Results improved $1,017.7 million in 2016 in Malaysia primarily due to no repeat of impairment expense in 2016, lower lease operating expense, lower depreciation expense and lower dry hole costs. Lease operating expenses decreased in the 2016 period by $27.6 million due to lower maintenance and logistic costs and lower well work together with lower volume sold compared to 2015. Depreciation expense was $82.2 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.

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

Third quarter 2016 vs. 2015 (Contd.)

Other international operations reported a loss of $8.1 million in the third quarter of 2016 compared to a loss of $28.6 million in the 2015 quarter. The $20.5 million improvement in the 2016 period was primarily related to lower exploration expenses, lower selling and general expenses and income tax benefits reported on investments in foreign areas.

Total hydrocarbon production averaged 169,844 barrels of oil equivalent per day in the 2016 third quarter, which represented a decrease of 18.2% from the 207,586 barrels of oil equivalents per day produced in the 2015 quarter. Average crude oil and condensate production was 96,476 barrels per day in the third quarter of 2016 compared to 125,170 barrels per day in the third quarter of 2015. Crude oil production decreased 14,997 barrels in the Eagle Ford Shale area of South Texas in 2016 due to well decline and significantly less drilling in the last half of 2015 and first half of 2016. Light oil production increased by 1,197 barrels per day in 2016 due to the completion of the Company's acquisition of acreage in the Kaybob Duvernay lands and Placid Montney lands in Alberta. 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 due to better uptime at both the Hibernia and Terra Nova fields. Synthetic oil production was nil in 2016 versus 10,907 barrels per day in 2015 due to the sale of its non-operated interest in Syncrude at the end of the second quarter 2016. Higher oil production in 2016 in Malaysia was primarily attributable to more production at Kakap, offset by decline in other fields. On a worldwide basis, the Company's crude oil and condensate prices averaged $44.64 per barrel in the third quarter 2016 compared to $46.20 per barrel in the 2015 period, a decline of 3.4% quarter to quarter. Total production of natural gas liquids (NGL) was 9,703 barrels per day in the 2016 third quarter compared to 11,093 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 $11.38 per barrel in the 2016 quarter compared to $10.25 per barrel in 2015. Natural gas sales volumes averaged 382 million cubic feet per day in the third quarter 2016 compared to 428 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 unplanned downtime and a lower entitlement in Sarawak in the 2016 period. North American natural gas sales prices averaged $1.96 per thousand cubic feet (MCF) in the 2016 quarter, 19.0% 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 $3.01 per MCF, compared to a price of $3.75 per MCF in the 2015 quarter.

Nine Months 2016 vs. 2015

United States exploration and production operations reported a loss of $158.5 million in the first nine months of 2016 compared to a loss of $218.1 million in the 2015 period. The loss decreased $59.6 million in 2016 compared to the 2015 period due to no impairment expense in 2016, plus lower expense in the current year for lease operations, depreciation, exploration and administrative expenses, offset in part by lower revenues. Revenue in the U.S. fell $434.8 million in the 2016 period due to both lower oil and natural gas realized sales prices and lower volumes sold, coupled with unrealized losses on marking open crude oil contracts to market value in the 2016 period versus unrealized gains in the 2015 period. Lease operating expenses decreased by $77.7 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 reducing costs coupled with lower variable costs based on volumes produced. Severance and ad valorem taxes in the first nine months of 2016 were $16.5 million lower than the 2015 period primarily due to weaker average commodity prices and lower volume sold. Depreciation expense decreased $165.9 million in 2016 compared to 2015 due to lower unit rates and lower volume sold. Unit rates improved in Eagle Ford Shale in the 2016 period due to lower drilling costs and migration of reserves, while the offshore Gulf of Mexico unit rates were improved primarily due to impairments reported in the prior year. Exploration expenses were down $100.1 million in the 2016 period primarily related to lower dry hole costs of $74.1 million and lower undeveloped lease amortization expense compared to the first nine months of 2015. Selling and general expenses were $18.3 million lower in the 2016 period primarily due to Company restructuring activities in both 2015 and 2016 periods.

Operations in Canada had a loss of $36.9 million in 2016 compared to a loss of $577.8 million in 2015. Canadian results of operations improved by $540.9 million in the 2016 period. Results for conventional operations improved by $470.3 million in 2016 due to lower impairment expense, 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, plus lower depreciation expense and lower lease

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

Nine Months 2016 vs. 2015 (Contd.)

operating expense. These improvements were partially offset by lower average realized sales prices for crude oil and natural gas. Lease operating expenses associated with conventional operations were $7.6 million lower in the first nine months of 2016 due to lower operating costs, lower plant workover costs and a weaker Canadian dollar exchange rate offset in part by higher processing costs for its Tupper area production. Depreciation expense was $33.5 million lower in the 2016 period compared to 2015 due primarily to impairment of its Seal area heavy oil property in the 2015 period. Impairment expense was $588.5 million lower in the first nine months of 2016, as low oil prices led to a write down of heavy oil properties at Seal in Western Canada in 2015 and the Terra Nova field offshore East Coast Canada in the first quarter of 2016. Synthetic operations generated $47.7 million in income in 2016 compared to a loss of $22.9 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 2016 was the primary driver of the improvement.

Malaysia operations reported earnings of $135.1 million in 2016 compared to a loss of $701.9 million during the same period in 2015. Results were up $837.0 million in 2016 in Malaysia primarily due to no impairment expense in the current year are lower depreciation and lease operating expenses in 2016, partially offset by lower 2016 revenues and no repeat of a $218.8 million after-tax gain on sale of a 10% interest in Malaysian assets in the 2015 period. Revenue declined by 356.2 million in 2016 driven by lower commodity prices received and lower volumes sold compared to 2015 coupled with no repeat of the 2015 gain on sale. Lease operating expenses decreased in the 2016 period by $68.3 million due to lower maintenance and logistic costs and cost cutting measures, and lower volume sold compared to 2015. Depreciation expense was $305.1 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 $39.2 million in the first nine months of 2016 compared to a loss of $130.7 million in the 2015 period. The 2016 period included lower dry hole costs of $21.4 million, with the higher 2015 costs primarily associated with unsuccessful wildcat drilling offshore Australia. Geological and geophysical costs were $16.9 million lower in the 2016 period, primarily due to less seismic data acquired in Australia. Other exploration expenses were $12.2 million lower in the current year, mostly attributable to the Company closing certain field offices beginning in late 2015 and lowering its cost structure. Other expenses were $20.9 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 the Republic of Congo. Selling and general expenses were $17.7 million lower in 2016 due to Company restructuring initiatives implemented in both 2015 and 2016.

Total worldwide production averaged 178,319 barrels of oil equivalent per day during the nine months ended September 30, 2016, down from 210,313 barrels of oil equivalent produced in the same period in 2015. Crude oil and condensate production in the first half of 2016 averaged 106,279 barrels per day compared to 128,888 barrels per day a year ago. Crude oil production decreased 11,633 barrels per day in the Eagle Ford Shale in 2016 due to well decline and significantly less drilling beginning in the last half of 2015 and continuing into 2016. 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 from the sale of its interest in Syncrude at the end of the second quarter of 2016 and maintenance work and downtime associated with forest fires in the surrounding area during the period leading up to the disposition. Lower oil production in 2016 in Malaysia was primarily attributable to natural well decline at most fields, partly offset by higher production at Kakap. For the first nine months of 2016, the Company’s sales price for crude oil and condensate averaged $40.67 per barrel, down from $49.58 per barrel in 2015. Total production of natural gas liquids was 9,275 barrels per day in the 2016 period compared to 10,431 barrels per day a year ago. The sales price for U.S. natural gas liquids averaged $10.31 per barrel in 2016 compared to $11.90 per barrel in 2015. Natural gas sales volumes decreased from 426 million cubic feet per day in 2015 to 377 million cubic feet per day in 2016. Natural gas sales volumes decreased in North America due to lower gas volume in the Gulf of Mexico primarily in the Dalmatian field and slightly lower volume from the Eagle Ford Shale area of South Texas, offset in part by higher gas production volumes in the Tupper area in Western Canada. Lower natural gas production in Malaysia was primarily due to higher unplanned downtime, lower entitlement at Sarawak and more gas injection at Kikeh. The average sales price for North American natural gas in the first nine months of 2016 was $1.61 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 $3.25 per MCF in 2016 compared to $4.31 per MCF in 2015.

Additional details about results of oil and gas operations are presented in the tables on pages 27 and 28.

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

Ex

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net crude oil and condensate produced – barrels per day	96,476	125,170	106,279	128,888
United States – Eagle Ford Shale	33,307	48,304	36,790	48,423
– Gulf of Mexico and other	11,722	16,992	12,791	14,027
Canada – light	1,288	91	791	104
– heavy	2,678	4,975	2,732	5,837
– offshore	9,400	. 6,846	8,483	7,413
– synthetic1	–	10,907	6,194	11,230
Malaysia1 – Sarawak	12,889	15,194	13,288	15,696
– Block K	25,192	21,861	25,210	26,158
Net crude oil and condensate sold – barrels per day	97,542	124,549	104,525	129,294
United States – Eagle Ford Shale	33,307	48,304	36,790	48,423
– Gulf of Mexico and other	11,722	16,992	12,791	14,027
Canada – light	1,288	91	791	104
– heavy	2,678	4,975	2,732	5,837
– offshore	9,027	5,611	8,576	7,238
– synthetic1	–	10,907	6,194	11,230
Malaysia1 – Sarawak	12,641	18,493	12,024	17,546
– Block K	26,879	19,176	24,627	24,889
Net natural gas liquids produced – barrels per day	9,703	11,093	9,275	10,431
United States – Eagle Ford Shale	6,940	8,192	6,972	7,744
– Gulf of Mexico and other	1,502	2,264	1,399	2,020
Canada	307	1	162	9
Malaysia1 – Sarawak	954	636	742	658
Net natural gas liquids sold – barrels per day	8,770	11,789	9,289	10,466
United States – Eagle Ford Shale	6,940	8,192	6,972	7,744
– Gulf of Mexico	1,502	2,264	1,399	2,020
Canada	307	1	162	9
Malaysia1 – Sarawak	21	1,332	756	693
Net natural gas sold – thousands of cubic feet per day	381,988	427,937	376,592	425,964
United States – Eagle Ford Shale	34,900	39,543	36,430	39,203
– Gulf of Mexico and other	16,873	47,987	19,012	53,010
Canada	204,816	196,111	206,458	194,136
Malaysia1 – Sarawak	115,535	128,963	103,327	117,339

– Block K	9,864	15,333	11,365	22,276
Total net hydrocarbons produced – equivalent barrels per day2	169,844	207,586	178,319	210,313
Total net hydrocarbons sold – equivalent barrels per day2	169,977	207,661	176,579	210,754

1 The Company sold a 10% interest in Malaysia properties on January 29, 2015. The Company sold its 5% non-operated interest in Syncrude Canada Ltd. on June 23, 2016. 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.

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Weighted average sales prices				
Crude oil and condensate – dollars per barrel				
United States – Eagle Ford Shale	$ 44.59	48.70	40.65	49.27
– Gulf of Mexico	43.93	44.94	40.53	49.45
Canada – light	36.36	37.70	41.04	43.41
– heavy	19.50	20.28	14.20	25.09
– offshore	45.87	48.09	40.15	53.77
– synthetic	–	46.53	35.59	49.72
Malaysia – Sarawak2	47.05	46.38	43.62	50.27
– Block K2	46.24	46.88	43.70	54.24
Natural gas liquids – dollars per barrel				
United States – Eagle Ford Shale	$ 10.89	10.26	10.06	11.52
– Gulf of Mexico	13.65	10.25	11.60	13.13
Canada1	39.23	–	41.04	22.31
Malaysia – Sarawak2	45.12	54.27	37.50	55.23
Natural gas – dollars per thousand cubic feet				
United States – Eagle Ford Shale	$ 2.24	2.39	1.69	2.39
– Gulf of Mexico	2.35	2.46	1.81	2.47
Canada1	1.88	2.42	1.58	2.44
Malaysia – Sarawak2	3.01	3.75	3.25	4.31
– Block K	0.23	0.24	0.24	0.24

1 U.S. dollar equivalent.

2 Prices are net of payments under terms of the respective production sharing contracts.

26

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

OIL AND GAS OPERATING RESULTS – THREE MONTHS ENDED SEPTEMBER 30, 2016 AND 2015

(Millions of dollars)	United States	Canada Conven-tional	Synthetic	Malaysia	Other	Total
Three Months Ended September 30, 2016						
Oil and gas sales and other operating revenues	$ 201.8	80.9	–	202.7	0.2	485.6
Lease operating expenses	59.6	30.7	–	29.4	–	119.7
Severance and ad valorem taxes	8.5	1.1	–	–	–	9.6
Depreciation, depletion and amortization	141.1	46.5	–	62.0	1.5	251.1
Accretion of asset retirement obligations	4.2	2.8	–	4.0	–	11.0
Exploration expenses						
Dry holes	0.8	–	–	0.4	(0.2)	1.0
Geological and geophysical	(0.1)	–	–	0.1	0.5	0.5
Other	2.5	–	–	–	5.5	8.0
	3.2	–	–	0.5	5.8	9.5
Undeveloped lease amortization	9.3	1.1	–	–	–	10.4
Total exploration expenses	12.5	1.1	–	0.5	5.8	19.9
Selling and general expenses	14.7	5.2	–	0.2	7.4	27.5
Other expenses	1.0	–	–	5.4	0.1	6.5
Results of operations before taxes	(39.8)	(6.5)	–	101.2	(14.6)	40.3
Income tax provisions (benefits)	(12.7)	(1.7)	–	36.2	(6.5)	15.3
Results of operations (excluding corporate overhead and interest)	$ (27.1)	(4.8)	–	65.0	(8.1)	25.0
Three Months Ended September 30, 2015						
Oil and gas sales and other operating revenues	$ 335.1	76.4	46.8	207.3	–	665.6
Lease operating expenses	66.9	22.6	37.3	57.0	–	183.8
Severance and ad valorem taxes	12.1	0.9	1.3	–	–	14.3
Depreciation, depletion and amortization	220.8	51.6	12.1	144.2	1.6	430.3
Accretion of asset retirement obligations	5.2	1.6	1.3	3.8	–	11.9
Impairment of assets	144.8	683.6	–	1,472.6	–	2,301.0
Exploration expenses						
Dry holes	10.2	–	–	14.1	(2.9)	21.4
Geological and geophysical	2.5	–	–	–	4.8	7.3
Other	1.8	0.1	–	–	11.0	12.9

	14.5	0.1	–	14.1	12.9	41.6
Undeveloped lease amortization	12.0	3.9	–	–	0.6	16.5
Total exploration expenses	26.5	4.0	–	14.1	13.5	58.1
Selling and general expenses	22.9	5.1	0.2	3.3	15.2	46.7
Other expenses	0.9	–	–	17.3	–	18.2
Results of operations before taxes	(165.0)	(693.0)	(5.4)	(1,505.0)	(30.3)	(2,398.7)
Income tax benefits	(57.2)	(190.2)	(1.2)	(552.3)	(1.7)	(802.6)
Results of operations (excluding corporate overhead and interest)	$ (107.8)	(502.8)	(4.2)	(952.7)	(28.6)	(1,596.1)

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

OIL AND GAS OPERATING RESULTS – NINE MONTHS ENDED SEPTEMBER 30, 2016 AND 2015

(Millions of dollars)	United States	Canada Conventional	Synthetic	Malaysia	Other	Total
Nine Months Ended September 30, 2016						
Oil and gas sales and other operating revenues	$ 520.2	200.2	64.2	541.4	0.2	1,326.2
Lease operating expenses	169.6	73.3	69.9	122.5	–	435.3
Severance and ad valorem taxes	30.0	3.2	2.5	–	–	35.7
Depreciation, depletion and amortization	456.5	137.5	16.5	170.0	4.6	785.1
Accretion of asset retirement obligations	12.8	8.2	2.4	12.1	–	35.5
Impairment of assets	–	95.1	–	–	–	95.1
Exploration expenses						
Dry holes	0.4	–	–	4.5	10.4	15.3
Geological and geophysical	0.6	2.9	–	0.6	4.8	8.9
Other	4.5	0.5	–	–	18.9	23.9
	5.5	3.4	–	5.1	34.1	48.1
Undeveloped lease amortization	31.9	3.4	–	–	0.5	35.8
Total exploration expenses	37.4	6.8	–	5.1	34.6	83.9
Selling and general expenses	49.9	20.9	0.5	8.6	26.6	106.5
Other expenses (benefits)	1.1	–	–	6.3	(8.8)	(1.4)
Results of operations before taxes	(237.1)	(144.8)	(27.6)	216.8	(56.8)	(249.5)
Income tax provisions (benefits)	(78.6)	(60.2)	(75.3)	81.7	(17.6)	(150.0)
Results of operations (excluding corporate overhead and interest)	$ (158.5)	(84.6)	47.7	135.1	(39.2)	(99.5)
Nine Months Ended September 30, 2015						
Oil and gas sales and other operating revenues	$ 955.0	275.7	152.7	897.6	–	2,281.0
Lease operating expenses	247.3	80.9	124.7	190.8	–	643.7
Severance and ad valorem taxes	46.5	3.5	4.1	–	–	54.1
Depreciation, depletion and amortization	622.4	171.0	37.4	475.1	4.7	1,310.6
Accretion of asset retirement obligations	14.9	5.0	4.1	11.4	–	35.4
Impairment of assets	144.8	683.6	–	1,472.6	–	2,301.0

Exploration expenses						
Dry holes	74.5	–	–	14.1	31.8	120.4
Geological and geophysical	7.8	–	–	1.2	21.7	30.7
Other	6.7	0.5	–	–	31.1	38.3
	89.0	0.5	–	15.3	84.6	189.4
Undeveloped lease amortization	48.5	12.4	–	–	1.5	62.4
Total exploration expenses	137.5	12.9	–	15.3	86.1	251.8
Selling and general expenses	68.2	18.4	0.7	4.5	44.3	136.1
Other expenses	8.4	44.0	–	17.3	12.1	81.8
Results of operations before taxes	(335.0)	(743.6)	(18.3)	(1,289.4)	(147.2)	(2,533.5)
Income tax provisions (benefits)	(116.9)	(188.7)	4.6	(587.5)	(16.5)	(905.0)
Results of operations (excluding corporate overhead and interest)	$ (218.1)	(554.9)	(22.9)	(701.9)	(130.7)	(1,628.5)

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 after tax cost of $39.6 million in the 2016 third quarter compared to after-tax income of $9.0 million in the same 2015 quarter. The $48.6 million higher cost in the 2016 period is primarily due to lower benefits from foreign currency exchange and higher net interest costs, partially offset by lower administrative costs and lower tax benefits. An after-tax gain of $11.5 million occurred in 2016 on transactions denominated in foreign currencies, while the 2015 quarter had an after-tax gain of $47.8 million. Net interest costs increased $9.1 million in the 2016 period primarily due to issuance of $550 million in notes, in August 2016, that mature in 2024 and an increase of 1.00% on the coupon rates on $1.5 billion of the Company's outstanding notes effective June 1, 2016 following a downgrade by Moody's Investor Services in February 2016.

For the first nine months of 2016, corporate activities reflected after-tax costs of $111.7 million compared to after-tax costs of $44.0 million a year ago. The $67.7 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 $32.9 million occurred in 2016 on transactions denominated in foreign currencies compared to an after-tax gain of $82.3 million a year ago. Net interest costs increased $17.0 million in the 2016 period primarily due to the aforementioned reasons above.

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 nine-month periods ended September 30, 2016 and 2015 are reflected in the following table.

(Millions of dollars)		Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
U.K. refining and marketing	$	(1.0)	(8.3)	(1.1)	(11.0)
U.K. exploration and production		(0.6)	–	0.2	(0.2)
Loss from discontinued operations	$	(1.6)	(8.3)	(0.9)	(11.2)

Financial Condition

Net cash provided by continuing operating activities was $280.3 million for the first nine-months of 2016 compared to $1,096.5 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, and payoff of deepwater rig exit costs, offset in part by lower lease operating expenses. Changes in noncash operating working capital from continuing operations used cash of $152.6 million during the first nine-months of 2016, compared to generating cash of $97.0 million in 2015. The use of cash in 2016 included $266.6 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 $1,154.6 million in 2016 compared to $423.8 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 $712.9 million in the 2016 period and $852.4 million in 2015 from maturity of Canadian government securities that had maturity dates greater than 90 days at acquisition. The Company borrowed $541.4 million in the 2016 period with the proceeds from the offering to be used for general corporate purposes.

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 $781.7 million and $1,975.1 million in the nine-month period ended September 30, 2016 and 2015, respectively. Capital expenditures were significantly lower in 2016 compared to 2015 primarily due to the Company lowering its capital spending in response to lower commodity prices. Total cash dividends to shareholders amounted to $163.6 million in 2016 and $184.8 million in 2015. Beginning in the third quarter 2016, the Company decreased its quarterly dividend to $0.25 per share, which represents a 29% reduction from the previous quarterly level of $0.35 per share. 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 $865.3 million in the 2015 period. The Company repaid debt in the amount of $600.0 million in the nine-month period of 2016 on its revolving credit facility maturing in June 2017. The debt repayment was funded using proceeds from the sale of assets. In the first nine months of 2015, the Company expended $250.0 million to acquire 5,967,313 shares of Common stock. 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:

	Nine Months Ended September 30,	
(Millions of dollars)	2016	2015
Capital Expenditures		
Exploration and production	$ 614.6	1,631.5
Corporate	20.7	37.5
Total capital expenditures	$ 635.3	1,669.0

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 Placid 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

	Nine Months Ended September 30,	
(Millions of dollars)	2016	2015
Property additions and dry hole costs per cash flow statements	$ 781.7	1,975.1
Geophysical and other exploration expenses	32.8	69.0
Capital expenditure accrual changes and other	(179.2)	(375.1)
Total capital expenditures	$ 635.3	1,669.0

Working capital (total current assets less total current liabilities) at September 30, 2016 was $690.9 million, $917.1 million more than December 31, 2015, with the increase primarily attributable to cash generated from the 2016 issuance of $550 million in long-term notes maturing in 2024, plus cash proceeds from asset dispositions that were used to fund deepwater rig contract exit and other accrued cost and other operating activities.

At September 30, 2016, long-term debt of $2,973.9 million had decreased by $66.7 million compared to December 31, 2015. Long-term debt was paid down in 2016 using part of the sales proceeds from Canadian asset disposition offset in part by the 2016 issuance of $550 million in notes maturing in 2024. A summary of capital employed at September 30, 2016 and December 31, 2015 follows.

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	September 30, 2016		December 31, 2015	
(Millions of dollars)	Amount	%	Amount	%
Capital employed				
Long-term debt	$ 2,973.9	36.9 %	$ 3,040.6	36.4 %
Stockholders' equity	5,085.6	63.1	5,306.7	63.6
Total capital employed	$ 8,059.5	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 September 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 $198.0 million in Canada and $92.4 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. Additionally, the Company could incur U.S. tax charges if amounts drawn in the U.S. on its 2016 revolving credit facility, guaranteed by a foreign subsidiary, are outstanding at the end of a quarterly reporting period.

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 an ASU to establish 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.

Statement of Cash Flows

In August 2016, the FASB issued Accounting Standards Update ("ASU") No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments ("ASU 2016-15)"). ASU 2016-15 reduces diversity in practice in how certain transactions are classified in the statement of cash flows. The amendments in ASU 2016-15 provide guidance on specific cash flow issues including debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, and distributions received from equity method investees. ASU 2016-15 is effective for annual and interim periods beginning after December 5, 2017. The Company is currently assessing the potential impact of ASU 2016-15 on its consolidated financial statements.

Outlook

Worldwide crude oil prices improved during October 2016 when compared to the average prices during the third quarter of 2016 as global petroleum inventories began to show signs of decline. The U.S. shed more than 40 million barrels of crude oil stocks from the historically high levels reached during the second quarter. North American natural gas prices have improved in October 2016 relative to the third quarter of 2016 as the summer injection season came to a close. The U.S commercial natural gas inventory excess to the prior year has been reduced by more than 90% since the end of the withdrawal season in March. The Company expects its total oil and natural gas production to average 162,000 to 164,000 barrels of oil

Outlook (Contd)

equivalent per day in the fourth 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 Placid Montney interests in Canada.

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 borrowed money. As of September 30, 2016, there were no funds borrowed under either of its bank credit facilities. The Company's current 2016 outlook calls for no borrowings under its revolving credit agreement during the last quarter 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 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 continued, could lead to lower production levels in future periods. A further deterioration of low oil and/or gas prices, 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 October 31, 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	Oct. – Dec. 2016	25,000 bbls/d	$50.67 per bbl.
U.S. Oil	West Texas Intermediate	Jan. – Dec. 2017	18,000 bbls/d	$50.60 per bbl.
Canadian Natural Gas	TCPL–NOVA System	Oct. – Dec. 2016	99 mmcf/d	C$3.00 per mcf
Canadian Natural Gas	TCPL–NOVA System	Jan. 2017 – Dec. 2017	99 mmcf/d	C$2.89 per mcf
Canadian Natural Gas	TCPL–NOVA System	Jan. 2018 – 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 33 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 September 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 $41.4 million, while a 10% decrease in the benchmark price would have increased the recorded net asset by a similar amount.

There were derivative foreign exchange contracts in place at September 30, 2016 to hedge the value of the U.S. dollar against the Canadian dollar for certain U.S. dollar receivables. A 10% strengthening of the U.S. dollar against the Canadian dollar would have decreased the recorded net asset associated with these contracts by approximately $2.5 million, while a 10% weakening of the U.S. dollar would have increased the recorded net asset by approximately $2.5 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 2016, the Company implemented 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 September 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 35 of this Form 10-Q report lists the exhibits that are hereby filed or incorporated by reference.

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)

November 2, 2016

(Date)

EXHIBIT INDEX

Exhibit No.	
4.1	Third Supplemental Indenture dated as of August 17, 2016 between Murphy Oil Corporation and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Murphy’s Current Report on Form 8-K filed August 17, 2016)
10.1	Credit Agreement dated as of August 10, 2016 among Murphy Oil Corporation, Murphy Exploration & Production Company – International, and Murphy Oil Company Ltd., as borrowers, JPMorgan Chase Bank, N.A., as administrative agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Murphy’s Current Report on Form 8-K filed August 12, 2016)
10.2	Third Amendment to 5-Year Revolving Credit Agreement dated as of August 10, 2016 among Murphy Oil Corporation, Canam Offshore Limited, and Murphy Oil Company Ltd., as borrowers, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to Murphy’s Current Report on Form 8-K filed August 12, 2016)
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.