MURPHY OIL CORP /DE
Form 10-Q
August 02, 2017

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2017

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", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange act.

Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

Emerging growth company [ ]

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934

(§240.12b-2 of this chapter). Emerging growth company [ ]

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to

Section 13(a) of the Exchange Act. [ ]

Number of shares of Common Stock, $1.00 par value, outstanding at July 31, 2017 was 172,572,873

MURPHY OIL CORPORATION

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PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED BALANCE SHEETS (unaudited)

(Thousands of dollars)

	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,058,487	872,797
Canadian government securities with maturities greater than 90 days at the date of acquisition	40,104	111,542
Accounts receivable, less allowance for doubtful accounts of $1,605 in 2017 and 2016	232,558	357,099
Inventories, at lower of cost or market	131,952	127,071
Prepaid expenses	55,237	63,604
Assets held for sale	22,245	27,070
Total current assets	1,540,583	1,559,183
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $11,795,083 in 2017 and $12,607,815 in 2016	8,164,116	8,316,188
Deferred charges and other assets	432,102	420,489
Total assets	$ 10,136,801	10,295,860
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 559,216	569,817
Accounts payable	595,775	784,975
Income taxes payable	56,304	13,920
Other taxes payable	38,284	28,167
Other accrued liabilities	105,111	102,777
Liabilities associated with assets held for sale	2,952	2,776
Total current liabilities	1,357,642	1,502,432
Long-term debt, including capital lease obligation	2,367,059	2,422,750
Deferred income taxes	107,573	69,081
Asset retirement obligations	703,364	681,528
Deferred credits and other liabilities	623,475	617,490

Liabilities associated with assets held for sale	–	85,900
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 2017 and 2016	195,056	195,056
Capital in excess of par value	903,542	916,799
Retained earnings	5,684,211	5,729,596
Accumulated other comprehensive loss	(529,592)	(628,212)
Treasury stock	(1,275,529)	(1,296,560)
Total stockholders' equity	4,977,688	4,916,679
Total liabilities and stockholders' equity	$ 10,136,801	10,295,860

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		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
Revenues				
Sales and other operating revenues	$ 509,613	411,217	1,054,271	840,311
Gain (loss) on sale of assets	(1,334)	3,809	130,648	3,831
Interest and other income (loss)	(33,782)	22,436	(45,803)	23,615
Total revenues	474,497	437,462	1,139,116	867,757
Costs and expenses				
Lease operating expenses	111,179	156,530	233,321	315,633
Severance and ad valorem taxes	10,742	13,439	21,955	26,076
Exploration expenses	20,201	37,128	48,864	64,044
Selling and general expenses	57,332	67,113	111,587	140,620
Depreciation, depletion and amortization	234,992	255,239	471,146	541,388
Accretion of asset retirement obligations	10,428	12,346	20,984	24,471
Impairment of assets	–	–	–	95,088
Interest expense	46,261	35,058	91,951	67,119
Interest capitalized	(1,116)	(608)	(2,209)	(2,449)
Other expense (benefit)	6,377	(7,516)	8,534	(7,932)
Total costs and expenses	496,396	568,729	1,006,133	1,264,058
Income (loss) from continuing operations before income taxes	(21,899)	(131,267)	132,983	(396,301)
Income tax expense (benefit)	(4,545)	(134,172)	92,842	(199,721)
Income (loss) from continuing operations	(17,354)	2,905	40,141	(196,580)
Income (loss) from discontinued operations, net of income taxes	(217)	25	752	708
NET INCOME (LOSS)	$ (17,571)	2,930	40,893	(195,872)
INCOME (LOSS) PER COMMON SHARE – BASIC				
Continuing operations	$ (0.10)	0.02	0.23	(1.14)
Discontinued operations	–	–	0.01	–
Net income (loss)	$ (0.10)	0.02	0.24	(1.14)
INCOME (LOSS) PER COMMON SHARE – DILUTED				
Continuing operations	$ (0.10)	0.02	0.23	(1.14)
Discontinued operations	–	–	0.01	–
Net income (loss)	$ (0.10)	0.02	0.24	(1.14)

Cash dividends per Common share	0.25	0.35	0.50	0.70
Average Common shares outstanding (thousands)				
Basic	172,558	172,197	172,482	172,150
Diluted	172,558	172,800	173,017	172,150

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 June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Net income (loss)	$ (17,571)	2,930	40,893	(195,872)
Other comprehensive income, net of tax				
Net gain from foreign currency translation	70,220	13,222	92,884	161,891
Retirement and postretirement benefit plans	2,386	2,513	4,773	5,029
Deferred loss on interest rate hedges reclassified to interest expense	481	481	963	963
Other comprehensive income	73,087	16,216	98,620	167,883
COMPREHENSIVE INCOME (LOSS)	$ 55,516	19,146	139,513	(27,989)

See Notes to Consolidated Financial Statements, page 7.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Thousands of dollars)

	Six Months Ended June 30, 2017	2016
OPERATING ACTIVITIES		
Net income (loss)	$ 40,893	(195,872)
Adjustments to reconcile net loss to net cash provided by continuing operations activities:		
Income from discontinued operations	(752)	(708)
Depreciation, depletion and amortization	471,146	541,388
Impairment of assets	–	95,088
Amortization of deferred major repair costs	–	3,798
Dry hole costs	1,904	14,270
Amortization of undeveloped leases	20,306	25,419
Accretion of asset retirement obligations	20,984	24,471
Deferred income tax expense (benefit)	33,130	(316,201)
Pretax gains from disposition of assets	(130,648)	(3,831)
Net (increase) decrease in noncash operating working capital	42,581	(86,793)
Other operating activities, net	91,918	12,349
Net cash provided by continuing operations activities	591,462	113,378
Investing Activities		
Property additions and dry hole costs	(431,654)	(604,587)
Proceeds from sales of property, plant and equipment	64,303	1,153,325
Purchases of investment securities1	(212,661)	(651,218)
Proceeds from maturity of investment securities1	284,193	701,378
Other investing activities, net	–	(7,640)
Net cash (required) provided by investing activities	(295,819)	591,258
Financing Activities		
Repayments of debt	–	(600,000)
Capital lease obligation payments	(11,983)	(5,172)
Withholding tax on stock-based incentive awards	(7,081)	(1,138)
Cash dividends paid	(86,278)	(120,535)
Net cash required by financing activities	(105,342)	(726,845)
Cash Flows from Discontinued Operations		
Operating activities	–	5,185
Changes in cash included in current assets held for sale	–	(5,185)
Net change in cash and cash equivalents of discontinued operations	–	–

Effect of exchange rate changes on cash and cash equivalents	(4,611)	6,509
Net increase in cash and cash equivalents	185,690	(15,700)
Cash and cash equivalents at beginning of period	872,797	283,183
Cash and cash equivalents at end of period	$ 1,058,487	267,483

1Investments 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)

	Six Months Ended June 30,	
	2017	2016
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	$ –	–
Common Stock – par $1.00, authorized 450,000,000 shares, issued 195,055,724 shares at June 30, 2017 and 2016.		
Balance at beginning of period	195,056	195,056
Exercise of stock options	–	–
Balance at end of period	195,056	195,056
Capital in Excess of Par Value		
Balance at beginning of period	916,799	910,074
Restricted stock transactions and other	(26,483)	(10,078)
Stock-based compensation	13,302	14,454
Other	(76)	(214)
Balance at end of period	903,542	914,236
Retained Earnings		
Balance at beginning of period	5,729,596	6,212,201
Net income (loss) for the period	40,893	(195,872)
Cash dividends	(86,278)	(120,535)
Balance at end of period	5,684,211	5,895,794
Accumulated Other Comprehensive Loss		
Balance at beginning of period	(628,212)	(704,542)
Foreign currency translation gain, net of income taxes	92,884	161,891
Retirement and postretirement benefit plans, net of income taxes	4,773	5,029
Deferred loss on interest rate hedges reclassified to interest expense, net of income taxes	963	963
Balance at end of period	(529,592)	(536,659)
Treasury Stock		
Balance at beginning of period	(1,296,560)	(1,306,061)
Sale of stock under employee stock purchase plans	145	334
Awarded restricted stock, net of forfeitures	20,886	8,993
Balance at end of period – 22,482,851 shares of Common Stock in 2017 and 22,856,616 shares of Common Stock in 2016, at cost	(1,275,529)	(1,296,734)
Total Stockholders' Equity	$ 4,977,688	5,171,693

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.

INTERIM FINANCIAL STATEMENTS – In the opinion of Murphy's management, the unaudited financial statements presented herein include all accruals necessary to present fairly the Company's financial position at June 30, 2017 and December 31, 2016, and the results of operations, cash flows and changes in stockholders' equity for the interim periods ended June 30, 2017 and 2016, 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 2016 Form 10-K report, as certain notes and other pertinent information have been abbreviated or omitted in this report. Financial results for the three-month and six-month periods ended June 30, 2017 are not necessarily indicative of future results.

Note B – Property, Plant and Equipment

Exploratory Wells

Under Financial Accounting Standards Board (FASB) guidance exploratory well costs should continue to be capitalized when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

At June 30, 2017, the Company had total capitalized exploratory well costs pending the determination of proved reserves of $175.5 million. The following table reflects the net changes in capitalized exploratory well costs during the six-month periods ended June 30, 2017 and 2016.

(Thousands of dollars)	2017	2016
Beginning balance at January 1	$ 148,500	130,514
Additions pending the determination of proved reserves	48,764	800
Reclassifications to proved properties based on the determination of proved reserves	(13,370)	–
Capitalized exploratory well costs charged to expense	(8,360)	–
Other adjustments	–	(3,205)
Balance at June 30	$ 175,534	128,109

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

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

	June 30, 2017			2016		
(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	$ 57,900	3	3	$ 63,617	5	5
One to two years	53,023	3	3	–	–	–
Two to three years	–	–	–	31,627	2	–
Three years or more	64,611	6	–	32,865	4	–
	$ 175,534	12	6	$ 128,109	11	5

Of the $117.6 million of exploratory well costs capitalized more than one year at June 30, 2017, $70.4 million is in Brunei, $43.2 million is in Vietnam and $4.0 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. The capitalized well costs charged to expense during the first six months of 2017 included one well in Block H, offshore Malaysia in which development of the well could not be justified due to noncommercial hydrocarbon quantities found and change in development plan due to low commodity prices.

Divestments

In January 2017, a Canadian subsidiary of the Company completed its disposition of the Seal field in Western Canada. Total cash consideration to Murphy upon closing of the transaction was approximately $49.0 million. Additionally, the buyer assumed the asset retirement obligation of approximately $85.9 million. A $132.4 million pretax gain was reported in the first quarter of 2017 related to the sale. Also, in January 2017, a U.S. subsidiary of the Company completed its disposition of several non-core properties in the North Tilden area of Eagle Ford Shale. Total cash consideration to Murphy upon closing of the transaction was approximately $14.8 million. There was no gain or loss recorded related to this sale.

During the second quarter 2016, a Canadian subsidiary of the Company completed the sale of its five percent, non-operated working interest in Syncrude Canada Ltd. (“Syncrude”) asset to Suncor Energy Inc. (“Suncor”). The Company received net cash proceeds of $739.1 million and recorded an after-tax gain of $71.7 million in the second quarter of 2016 associated with the Syncrude divestiture.

During the second quarter 2016, a Canadian subsidiary of the Company completed a divestiture of natural gas processing and sales pipeline assets that support Murphy’s Montney natural gas fields in the Tupper area of northeastern British Columbia. A gain on sale of approximately $187.0 million was deferred and is being recognized over the next 19 years in the Canadian operating segment. The Company amortized approximately $3.4 million of the deferred gain during the six-month period ended June 30, 2017. The remaining deferred gain of $179.8 million was included as a component of deferred credits and other liabilities in the Company’s Consolidated Balance Sheets.

Acquisitions

During the second quarter 2016, a Canadian subsidiary acquired 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 Placid Montney lands in Alberta, the majority of which was unproved. Under the terms of the joint venture, the total consideration amounts to approximately $375.0 million of which Murphy paid $206.7 million in cash at closing, subject to normal closing adjustments, and an additional $168.0 million in the form of a carried interest on the Kaybob Duvernay property. $24.7 million of the carried interest had been paid at June 30, 2017. The carry is to be paid over a period of up to five years from 2016.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

Impairments

During the first quarter of 2016, declines in future oil and gas prices led to impairments in certain of the Company's producing properties and the Company recorded pretax noncash impairment charges of $95.1 million to reduce the carrying values to their estimated fair values for the Terra Nova field offshore Canada and the Western Canada onshore heavy oil producing properties at Seal. The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges, costs, and a discount rate believed to be consistent with those used by principal market participants in the applicable region.

Other

The Company has an interest in the Kakap field in Block K Malaysia. The Kakap field is operated by another company and was jointly developed with the Gumusut field owned by others. As required by the agreements governing the field, a redetermination (unitization) review was required in 2016. In the fourth quarter 2016, the Company recorded $39.1 million in redetermination (unitization) expense related to an expected reduction in the Company's working interest covering the period from inception through year-end 2016 at Kakap. In February 2017, PETRONAS officially approved the redetermination that reduces the Company's working interest, from 8.6% to approximately 6.7%, effective April 1, 2017. The Company partially settled $21.8 million of the redetermination expense in cash in the second quarter of 2017. The Company currently expects to settle the remainder in the third quarter of 2017. It is possible that the final adjustment amount could be different than the current estimate. Due to the change in working interest, the future payments under a capital lease of a floating, production and storage facility in the Kakap field are lower and the Company has reduced the total debt recorded on the Consolidated Balance Sheet by approximately $56.7 million, with a similar reduction to Property, plant and equipment.

Note C – Discontinued Operations

The Company has accounted for its former U.K. refining and marketing operations as discontinued operations for all periods presented. The results of operations associated with discontinued operations for the three-month and six-month periods ended June 30, 2017 and 2016 were as follows:

(Thousands of dollars)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Revenues	$ 717	151	1,739	835
Income (loss) before income taxes	(217)	25	752	708
Income tax benefit	–	–	–	–
Income (loss) from discontinued operations	$ (217)	25	752	708

The following table presents the carrying value of the major categories of assets and liabilities of U.K. refining and marketing operations reflected as held for sale on the Company's Consolidated Balance Sheets at June 30, 2017 and December 31, 2016.

(Thousands of dollars)	June 30, 2017	December 31, 2016
Current assets		
Cash	$ 13,050	4,126
Accounts receivable	9,195	22,944
Total current assets held for sale	$ 22,245	27,070
Current liabilities		
Accounts payable	$ 508	270
Refinery decommissioning cost	2,444	2,506
Total current liabilities associated with assets held for sale	$ 2,952	2,776

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note D – Financing Arrangements and Debt

At June 30, 2017, the Company has a $1.1 billion senior unsecured guaranteed credit facility (2016 facility) with a major banking consortium, which expires in August 2019. At June 30, 2017, the Company had no outstanding borrowings under the 2016 facility, however, there were $178.1 million of outstanding letters of credit. Advances under the 2016 facility will accrue interest based, at the Company's option, on either the London Interbank Offered rate plus an applicable margin (Eurodollar rate) or the alternate base rate (as defined in the 2016 facility agreement) plus an applicable margin. Had there been any amounts borrowed under the 2016 facility at June 30, 2017, the applicable base rate would have been 5.25%. At June 30, 2017, the Company was in compliance with all covenants related to the 2016 facility.

The Company also has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through October 2018.

The Company and its partners are parties to a 25-year lease of production equipment at the Kakap field offshore Malaysia. The lease has been accounted for as a capital lease, and payments under the agreement are to be made over a 15-year period through June 2028. Current maturities of long-term debt and long-term debt on the Consolidated Balance Sheet included $9.6 million and $137.9 million, respectively, associated with this lease at June 30, 2017.

Note E – Other Financial Information

Additional disclosures regarding cash flow activities are provided below.

	Six Months Ended June 30,	
(Thousands of dollars)	2017	2016
Net (increase) decrease in operating working capital other than cash and cash equivalents:		
Decrease in accounts receivable	$ 125,283	109,105
Decrease (increase) in inventories	5,918	(4,659)
Decrease in prepaid expenses	9,206	99,524
Decrease in other	–	5,564

Decrease in accounts payable and accrued liabilities	(136,500)	(337,302)*
Increase in current income tax liabilities	38,674	40,975
Net (increase) decrease in noncash operating working capital	$ 42,581	(86,793)
Supplementary disclosures:		
Cash income taxes paid, net of refunds	$ 9,448	(4,367)
Interest paid, net of amounts capitalized	72,136	52,654
Non-cash investing activities:		
Asset retirement costs capitalized	$ 797	8,693
Decrease in capital expenditure accrual	43,370	165,329

* 2016 balances included payments for deepwater rig contract exit of $261.8 million.

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

The table that follows provides the components of net periodic benefit expense for the three-month and six-month periods ended June 30, 2017 and 2016.

	Three Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2017	2016	2017	2016
Service cost	$ 2,030	2,770	424	675
Interest cost	6,287	8,865	967	1,107
Expected return on plan assets	(6,475)	(9,698)	–	–
Amortization of prior service cost (credit)	254	321	(19)	(20)
Amortization of transitional asset	–	–	–	2
Recognized actuarial loss	3,509	3,718	–	36
Net periodic benefit expense	$ 5,605	5,976	1,372	1,800

	Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2017	2016	2017	2016
Service cost	$ 4,062	5,923	849	1,348
Interest cost	13,006	14,473	1,933	2,215
Expected return on plan assets	(13,660)	(15,083)	–	–
Amortization of prior service cost (credit)	508	640	(37)	(41)
Amortization of transitional asset	–	–	–	2
Recognized actuarial loss	7,063	7,247	–	75

Curtailments	–	822	–	(19)
Net periodic benefit expense	$ 10,979	14,022	2,745	3,580

During the six-month period ended June 30, 2017, the Company made contributions of $16.1 million to its defined benefit pension and postretirement benefit plans. Remaining required funding in 2017 for the Company's defined benefit pension and postretirement plans is anticipated to be $14.7 million. Curtailment expense for the six months ended June 30, 2016, shown in the table above relate to restructuring activities in the U.S. undertaken by the Company in the first quarter 2016.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note G – Incentive Plans

The costs resulting from all share-based payment transactions are recognized as an expense in the Consolidated Statements of 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 certain other 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 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; allowed shares not granted in an earlier year may be granted in future years. The Company also has a 2013 Stock Plan for Non-Employee Directors (Director Plan) that permits the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company's Non-Employee Directors.

The Company had an Employee Stock Purchase Plan (ESPP) that permitted the issuance of Company shares during 2016 and the first six months of 2017. The ESPP terminated on June 30, 2017 and was not renewed by the Company.

In February 2017, the Committee granted stock options for 599,000 shares at an exercise price of $28.505 per share. The Black-Scholes valuation for these awards was $7.96 per option. The Committee also granted 556,000 performance-based

RSU and 282,000 time-based RSU in February 2017. The fair value of the performance-based RSU, using a Monte Carlo valuation model, ranged from $24.10 to $28.28 per unit. The fair value of time-based RSU was estimated based on the fair market value of the Company's stock on the date of grant, which was $28.505 per share. Additionally, the Committee granted 329,400 SAR and 154,150 units of cash-settled RSU (RSUC) to certain employees. The SAR and RSUC 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 RSUC was equivalent to equity-settled restricted stock units granted. Also in February, the Committee granted 83,220 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 $28.84 per unit on date of grant.

For the first six months of 2017 and 2016, the Company had no stock options exercised.

Amounts recognized in the financial statements with respect to share-based plans are shown in the following table:

	Six Months Ended June 30,	
(Thousands of dollars)	2017	2016
Compensation charged against income (loss) before tax benefit	$ 16,722	24,288
Related income tax benefit recognized in income	5,425	8,210

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note H – Earnings per Share

Net income (loss) was used as the numerator in computing both basic and diluted income per Common share for the three-month and six-month periods ended June 30, 2017 and 2016. The following table reconciles the weighted-average shares outstanding used for these computations.

	Three Months Ended June 30,		Six Months Ended June 30,	
(Weighted-average shares)	2017	2016	2017	2016
Basic method	172,557,978	172,196,914	172,482,223	172,149,791
Dilutive stock options and restricted stock units*	–	602,913	534,441	–
Diluted method	172,557,978	172,799,827	173,016,664	172,149,791

*Due to net losses recognized by the Company for the three-month period ended June 30, 2017 and for the six-month period ended June 30, 2016, no unvested stock awards were included in the computation of diluted earnings per share because the effect would have been anti-dilutive.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Antidilutive stock options excluded from diluted shares	5,578,634	5,084,395	4,903,084	5,799,268
Weighted average price of these options	$ 46.64	$ 54.22	$ 52.01	$ 50.17

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 tax expense. For the three-month and six-month periods ended June 30, 2017 and 2016, the Company's effective income tax rates were as follows:

	2017	2016
Three months ended June 30	20.7%	102.2%
Six months ended June 30	69.8%	50.4%

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

The effective tax rate for the three-month period ended June 30, 2017 was below the U.S. statutory tax rate primarily due to a tax benefit recorded in the current period related to investments in foreign areas, partially offset by income tax expense in the same period related to undistributed foreign earnings in the amount of $5.8 million.

The effective tax rate for the six-month period ended June 30, 2017 was above the U.S. statutory tax rate primarily due to tax expense recorded in the current period related to undistributed foreign earnings partially offset by income tax benefit on investment in foreign areas. During the first six-months of 2017, the Company determined that prospective earnings from its Malaysian and Canadian subsidiaries will not be considered reinvested into local operations. Due to this change in assertion, the Company recorded a deferred tax charge of $60.4 million in the six-month period 2017 associated with the estimated tax consequence of the future repatriation of these subsidiaries earnings during the first six months 2017. This decision provides greater financial flexibility as it considers future domestic investment opportunities. The Company expects to incur further tax charges in future 2017 quarters for additional 2017 foreign earnings as they arise.

The effective tax rate benefit for both the three-month and six-month periods ended June 30, 2016 was above the U.S. statutory tax rate primarily due to deferred tax benefits recognized related to the Canadian asset dispositions and income tax benefits on investments in foreign areas.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note I – Income Taxes (Contd.)

The Company's tax returns in multiple jurisdictions are subject to audit by taxing authorities. These audits often take years to complete and settle. Although the Company believes that recorded liabilities for unsettled issues are adequate, additional gains or losses could occur in future years from resolution of outstanding unsettled matters. As of June 30, 2017, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States – 2011; Canada – 2012; Malaysia – 2010; and United Kingdom – 2014.

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 gain or loss associated with recording the fair value of these contracts was deferred in Accumulated Other Comprehensive Loss until the anticipated transactions occur. 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 it produces and sells. During the first six months 2017 and 2016, the Company had West Texas Intermediate (WTI) crude oil swap financial contracts to economically hedge a portion of its United States production. Under these contracts, which matured monthly, the Company paid the average monthly price in effect and received the fixed contract prices. At June 30, 2017, the Company had 22,000 barrels per day in

WTI crude oil swap financial contracts maturing ratably during 2017 at an average price of $50.41. At June 30, 2017, the fair value of WTI contracts of $18.3 million was included in Accounts Receivable. The impact of marking to market these 2017 commodity derivative contracts reduced the loss before income taxes by $14.9 million for the six-month period ended June 30, 2017.

At June 30, 2016, the Company had 25,000 barrels per day in WTI crude oil swap financial contracts maturing ratably during 2016. At June 30, 2016, the fair value of WTI contracts of $1.7 million was included in Accounts Receivable. The impact of marking to market these 2016 commodity derivative contracts decreased the loss before income taxes by $2.6 million for the six-month period ended June 30, 2016.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

Foreign Currency Exchange Risks

The Company is subject to foreign currency exchange risk associated with operations in countries outside the U.S. The Company had no foreign currency exchange short-term derivatives outstanding at June 30, 2017.

At June 30, 2016, short-term derivative instruments were outstanding in Canada for approximately $5.8 million, to manage the currency risks of certain U.S. dollar accounts receivable associated with sale of Canadian crude oil. The fair values of open foreign currency derivative contracts were liabilities of $0.1 million at June 30, 2016.

At June 30, 2017 and December 31, 2016, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

	June 30, 2017		December 31, 2016	
(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	$ 18,297	Accounts payable	$ (48,864)
Foreign exchange	Accounts receivable	–	Accounts payable	(73)

For the three-month and six-month periods ended June 30, 2017 and 2016, 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)

(Thousands of dollars)		Three Months Ended June 30,		Six Months Ended June 30,	
Type of Derivative Contract	Statement of Operations Location	2017	2016	2017	2016
Commodity	Sales and other operating revenues	$ 26,861	(47,738)	63,938	(34,549)
Foreign exchange	Interest and other income	(152)	26,481	73	26,786
		$ 26,709	(21,257)	64,011	(7,763)

Interest Rate Risks

Under hedge accounting rules, the Company deferred the net cost associated with derivative contracts purchased to manage interest rate risk associated with 10-year notes sold in May 2012 to match the payment of interest on these notes through 2022. During each of the six-month periods ended June 30, 2017 and 2016, $1.5 million of the deferred loss on the interest rate swaps was charged to Interest expense in the Consolidated Statement of Operations. The remaining loss deferred on these matured contracts at June 30, 2017 was $9.4 million, which is recorded, net of income taxes of $5.1 million, in Accumulated other comprehensive loss in the Consolidated Balance Sheet. The Company expects to charge approximately $1.5 million of this deferred loss to Interest expense in the Consolidated Statement of Operations during the remaining six months of 2017.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

Fair Values – Recurring

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

The carrying value of assets and liabilities recorded at fair value on a recurring basis at June 30, 2017 and December 31, 2016 are presented in the following table.

	June 30, 2017				December 31, 2016			
(Thousands of dollars)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Commodity derivative contracts	–	18,297	–	18,297	–	–	–	–
	$ –	18,297	–	18,297	–	–	–	–
Liabilities:								
Nonqualified employee savings plans	$ 14,652	–	–	14,652	13,904	–	–	13,904
Commodity derivative contracts	–	–	–	–	–	48,864	–	48,864
Foreign currency exchange derivative contracts	–	–	–	–	–	73	–	73
	$ 14,652	–	–	14,652	13,904	48,937	–	62,841

The fair value of WTI crude oil derivative contracts in 2017 and 2016 was based on active market quotes for WTI crude oil. The fair value of foreign exchange derivative contracts in each year was based on market quotes for similar contracts at the balance sheet dates. The income effect of changes in the fair value of crude oil derivative contracts is recorded in Sales and other operating revenues in the Consolidated Statements of Operations, while the effects of changes in fair value of foreign exchange derivative contracts is recorded in Interest and other income. The nonqualified employee savings plan is an unfunded savings plan through which participants seek a return via phantom investments in equity securities and/or mutual funds. The fair value of this liability was based on quoted prices for these equity securities and mutual funds. The income effect of changes in the fair value of the nonqualified employee savings plan is recorded in Selling and general expenses in the Consolidated Statements of Operations.

The Company offsets certain assets and liabilities related to derivative contracts when the legal right of offset exists. There were no offsetting positions recorded at June 30, 2017 and December 31, 2016.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

Fair Values – Nonrecurring

As a result of the fall in forward commodity prices during the first six months of 2016, the Company recognized approximately $95.1 million in pretax noncash impairment charges related to producing properties. The fair value information associated with these impaired properties is presented in the following table.

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

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

Note K – Accumulated Other Comprehensive Loss

The components of Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets at December 31, 2016 and June 30, 2017 and the changes during the six-month period ended June 30, 2017 are presented net of taxes in the following table.

Deferred
Loss on

(Thousands of dollars)		Foreign Currency Translation Gains (Losses)1	Retirement and Postretirement Benefit Plan Adjustments1		Interest Rate Derivative Hedges1		Total1
Balance at December 31, 2016	$	(446,555)	(171,305)		(10,352)		(628,212)
2017 components of other comprehensive income (loss):							
Before reclassifications to income		92,884	–		–		92,884
Reclassifications to income		–	4,773	2	963	3	5,736
Net other comprehensive income		92,884	4,773		963		98,620
Balance at June 30, 2017	$	(353,671)	(166,532)		(9,389)		(529,592)

1All amounts are presented net of income taxes.

2Reclassifications before taxes of $7,354 for the six-month period ended June 30, 2017 are included in the computation of net periodic benefit expense. See Note G for additional information. Related income taxes of $2,581 for the six-month period ended June 30, 2017 are included in Income tax expense.

3Reclassifications before taxes of $1,482 for the six-month period ended June 30, 2017 are included in Interest expense. Related income taxes of $519 for the six-month period ended June 30, 2017 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, tax rate changes and retroactive tax claims; royalty and revenue sharing changes; 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. Governmental actions are often motivated by political considerations, 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.

Note L – Environmental and Other Contingencies (Contd.)

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

The Company currently owns or leases, and has in the past owned or leased, properties at which hazardous substances have been or are being handled. Although the Company has used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under Murphy's control. Under existing laws the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. Certain of these historical properties are in various stages of negotiation, investigation, and/or cleanup and the Company is investigating the extent of any such liability and the availability of applicable defenses. The Company has retained certain liabilities related to environmental matters at formerly owned U.S. refineries that were sold in 2011. The Company also obtained insurance covering certain levels of environmental exposures related to past operations of these refineries. The Company has not retained any environmental exposure associated with Murphy's former U.S. marketing operations. 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 were notified. Based on the assessments done, the Company recorded $43.9 million in Other expense during 2015 associated with the estimated costs of remediating the site. As of June 30, 2017, the Company has a remaining accrued liability of $6.7 million associated with this event. During the first six months of 2017, the Company's Canadian subsidiary paid approximately $130.0 thousand as the complete and final resolution of administrative penalties assessed by the Alberta Energy Regulator regarding this matter. Further refinements in the estimated total cost to remediate the site are anticipated in future periods including possible 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 liability recorded. The Company retained the responsibility for this remediation upon sale of the Seal field in the first quarter of 2017.

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 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.

Note M – Commitments

The Company has entered into forward sales contracts to mitigate the price risk for a portion of its 2017 to 2020 natural gas sales volumes in Western Canada. During the period from July to December 2017 the natural gas sales contracts call for deliveries of 124 million cubic feet per day at Cdn $2.97 per MCF. During the period from January 2018 through December 2020 the natural gas sales contracts call for deliveries of 59 million cubic feet per day at Cdn $2.81 per MCF. During the period from November 2017 through March 2018 the natural gas sales contracts call for deliveries of 20 million cubic feet per day at US $3.51 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 June 30, 2017	Three Months Ended June 30, 2017 External Revenues	Three Months Ended June 30, 2017 Income (Loss)	Three Months Ended June 30, 2016 External Revenues	Three Months Ended June 30, 2016 Income (Loss)
Exploration and production*					
United States	$ 5,324.4	239.5	8.0	143.6	(65.7)
Canada	1,629.2	88.2	5.2	77.4	55.3
Malaysia	1,795.0	176.5	47.7	190.5	47.7
Other	136.1	–	7.2	(0.1)	(5.1)
Total exploration and production	8,884.7	504.2	68.1	411.4	32.2
Corporate	1,229.9	(29.7)	(85.5)	26.1	(29.3)
Assets/revenue/income (loss) from continuing operations	10,114.6	474.5	(17.4)	437.5	2.9
Discontinued operations, net of tax	22.2	–	(0.2)	–	–
Total	$ 10,136.8	474.5	(17.6)	437.5	2.9

(Millions of dollars)	Six Months Ended June 30, 2017 External Revenues	Six Months Ended June 30, 2017 Income (Loss)	Six Months Ended June 30, 2016 External Revenues	Six Months Ended June 30, 2016 Income (Loss)
Exploration and production*				
United States	$ 500.8	31.0	318.3	(131.4)
Canada	306.1	105.8	183.5	(31.9)
Malaysia	373.9	106.3	338.8	70.1
Other	–	0.1	–	(31.2)
Total exploration and production	1,180.8	243.2	840.6	(124.4)
Corporate	(41.7)	(203.1)	27.2	(72.2)
Revenue/income from continuing operations	1,139.1	40.1	867.8	(196.6)
Discontinued operations, net of tax	–	0.8	–	0.7
Total	$ 1,139.1	40.9	867.8	(195.9)

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

Note O – New Accounting Principles Adopted

Business Combinations

In January 2017, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) update to clarify the definition of a business with the objective of adding guidance to assist entities in evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The standard is intended to narrow the definition of a business by specifying the minimum inputs and processes and by narrowing the definition of outputs. The update is effective for annual and interim periods beginning in 2018 and is required to be adopted using a prospective approach, with early adoption permitted for transactions not previously reported in issued financial statements. The Company adopted this guidance in 2017 and it did not have a material 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. The Company adopted this guidance in 2017 and it did not have a material impact on its consolidated financial statements and footnote disclosures as there were no exercises of Company options during the period.

Note P – Recent Accounting Pronouncements

Compensation-Stock Compensation

In May 2017, FASB issued an ASU which amends the scope of modification accounting for share-based payment arrangements and provides guidance on the type of changes to the terms and conditions of share-based payment awards to which an entity would be required to apply modification accounting. The update is effective for annual periods beginning after December 15, 2017 and interim periods within the annual period. Early adoption is permitted. The Company does not believe the application of this accounting standard will have a material impact on its consolidated financial statements.

Compensation – Retirement Benefits

In March 2017, the FASB issued an update requiring that the service cost component of pension and postretirement benefit costs be presented in the same line item as other current employee compensation costs and other components of those benefit costs be presented separately from the service cost component and outside a subtotal of income from operations, if presented. The update also requires that only the service cost component of pension and postretirement benefit cost is eligible for capitalization. The update is effective for annual periods beginning after December 15, 2017 and interim periods within the annual period. Application is retrospective for the presentation of the components of these benefit costs and prospective for the capitalization of only service costs. Early adoption is permitted. The Company does not believe the application of this accounting standard will have a material impact on its consolidated financial statements.

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 ASU's 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. Additional disclosures will be required to describe the nature, amount, timing and uncertainly of revenue and cash flows from contracts with customers. The Company is required to adopt the new standard in the first quarter of 2018 using either the modified retrospective or cumulative effect transition method. The Company is performing an initial review of contracts in each of its revenue streams and is developing accounting policies to address the provisions of the ASU. While the Company does not currently expect net earnings to be materially impacted, the Company is analyzing whether total revenues and expenses will be significantly impacted. The Company continues to evaluate the impact of this and other provisions of these ASU's on its accounting policies, internal controls, and consolidated financial statements and related disclosures, and has not finalized any estimates of the potential impacts. The Company will adopt the new standard on January 1, 2018, using the modified retrospective method with a cumulative adjustment to retained earnings as necessary.

Leases

In February 2016, FASB issued an 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 right-of-use 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 the first quarter of 2019 and is currently analyzing its portfolio of contracts to assess the impact future adoption of this ASU may have on its consolidated financial statements.

Statement of Cash Flows

In August 2016, the FASB issued an ASU to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. The amendment provides guidance on specific cash flow issues including debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instrument 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. The ASU is effective for annual and interim periods beginning after December 15, 2017. The Company is currently assessing the potential impact of this ASU on its consolidated financial statements.

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

Overall Review

During the three-month and six-month periods ended June 30, 2017, worldwide benchmark oil and natural gas prices were above average comparable benchmark prices during 2016 contributing to a lower pretax loss in the second quarter 2017 and a higher pretax profit in the first six months of 2017.

For the three months ended June 30, 2017, the Company produced 163 thousand barrels of oil equivalent per day. There was no production in the quarter from Canadian heavy oil assets due to the 2016 and 2017 divestures of Syncrude and Seal assets, respectively. The Company invested $200 million in capital expenditure in the second quarter of 2017 primarily in the United States and Canada. The Company reported a net loss of $17.6 million, for the three months ended June 30, 2017, which included an unrealized foreign exchange after-tax loss of $31.7 million on intercompany loans in the quarter and a tax benefit of $21.0 million in the second quarter relating to investments in foreign areas.

For the six-month period ended June 30, 2017, the Company reported net income of $40.9 million, which included a pretax gain of $132.4 million on the sale of the Seal heavy oil property in Canada. The Company produced 166 thousand barrels of oil equivalent per day for the six-month 2017 period and invested $415 million in capital expenditures, principally in the United States and Canada. The Company incurred a deferred tax expense in the first six months of 2017 of $60.4 million on earnings of foreign subsidiaries, the majority of which was recorded in first quarter of 2017 and recorded an unrealized foreign exchange after-tax loss of $42.7 million on intercompany loans in the first six months of 2017. Further detail and discussion is provided in the narrative below.

Results of Operations

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

	Income (Loss) Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of dollars)	2017	2016	2017	2016
Exploration and production	$ 68.1	32.2	243.2	(124.4)
Corporate and other	(85.5)	(29.3)	(203.1)	(72.2)

Income (loss) from continuing operations	(17.4)	2.9	40.1	(196.6)
Discontinued operations	(0.2)	–	0.8	0.7
Net income (loss)	$ (17.6)	2.9	40.9	(195.9)

Second quarter 2017 vs. 2016

For the second quarter of 2017, Murphy's net loss was $17.6 million ($0.10 per diluted share) compared to net earnings of $2.9 million ($0.02 per diluted share) in the second quarter of 2016. Income (loss) from continuing operations fell from income of $2.9 million ($0.02 per diluted share) in the 2016 quarter to a loss of $17.4 million ($0.10 per diluted share) in 2017. The Company's exploration and production (E&P) continuing operations earned $68.1 million in the 2017 quarter compared to earnings of $32.2 million in the 2016 quarter. The E&P results in the 2017 quarter were favorably impacted by higher revenues due to higher realized oil and natural gas sales prices, lower lease operating expenses, lower depreciation expense, lower dry hole costs, lower selling and general expenses and higher tax benefits on investments in foreign areas, partially offset by lower volume sold. The corporate function had after-tax costs of $85.5 million in the 2017 second quarter compared to after-tax costs of $29.3 million in the 2016 period with the unfavorable variance in the current period due to losses from foreign exchange effects in the 2017 period versus gains in the same period of 2016, higher net interest expense and deferred tax charges in 2017 on undistributed earnings of certain foreign subsidiaries, offset in part by lower administrative costs in the current year. The 2017 second quarter included losses from discontinued operations of $0.2 million ($0.00 per diluted share).

Six months 2017 vs. 2016

For the first six months of 2017, Murphy's net income was $40.9 million ($0.24 per diluted share) compared to a net loss of $195.9 million ($1.14 per diluted share) for the same period in 2016. Income (loss) from continuing operations improved from a loss of $196.6 million ($1.14 per diluted share) in the first six months of 2016 to earnings of $40.1 million ($0.23 per diluted share) in 2017. In the first half of 2017, the Company's E&P continuing operations earned $243.2 million compared to a loss of $124.4 million in the same period of 2016. The results for the first half of 2017 were favorably impacted by higher revenues due to higher realized oil and natural gas sales prices, gain on sale of the Seal property in Western Canada, lower

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

Results of Operations (Contd.)

Six months 2017 vs. 2016 (contd.)

lease operating expenses, lower depreciation expense, non-recurring impairment expense in 2016, lower selling and general expenses, lower dry hole costs and higher tax benefits on investments in foreign areas, partially offset by higher other income

tax provisions and lower oil and natural gas volume sold. The corporate function had after-tax costs of $203.1 million in the first six months of 2017 compared to after-tax costs of $72.2 million in the 2016 period with the unfavorable variance in the current period due to losses from foreign exchange effects in the 2017 period versus gains in the same period of 2016, and higher net interest expense and deferred tax charges in 2017 on undistributed earnings of certain foreign subsidiaries, offset in part by lower administrative costs. Income from discontinued operations was $0.8 million ($0.01 per diluted share) in the first half of 2017 compared to income of $0.7 million ($0.00 per diluted share) in the 2016 period.

Exploration and Production

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

	Income (Loss)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of dollars)	2017	2016	2017	2016
Exploration and production				
United States	$ 8.0	(65.7)	31.0	(131.4)
Canada	5.2	55.3	105.8	(31.9)
Malaysia	47.7	47.7	106.3	70.1
Other International	7.2	(5.1)	0.1	(31.2)
Total	$ 68.1	32.2	243.2	(124.4)

Second quarter 2017 vs. 2016

United States E&P operations reported earnings of $8.0 million in the second quarter of 2017 compared to a loss of $65.7 million in the 2016 quarter. Results improved $73.7 million in the 2017 quarter compared to the 2016 period. Revenue in the U.S. increased by $95.9 million in the period due to the U.S. segment benefitting from unrealized gains on its open crude oil contract positions of $22.6 million versus losses of $59.4 million in the same period a year ago. Higher oil and natural gas realized sales prices more than offset impacts of lower volumes sold. Lease operating expenses decreased by $10.2 million due to lower costs in Eagle Ford Shale compared to the same quarter in 2016 with most of the reduction due to the Company's continuous focus on improving its cost structure. Depreciation expense decreased $11.1 million in 2017 compared to 2016 due primarily to lower volume sold in both Eagle Ford Shale and Gulf of Mexico and lower average unit rates in the Gulf of Mexico in the 2017 period. Selling and general expenses increased $3.9 million in the second quarter of 2017 primarily due to lower amounts allocated to lease operating expense in the 2017 period vs 2016.

Canadian E&P operations reported earnings of $5.2 million in the second quarter 2017 compared to earnings of $55.3 million in the 2016 quarter. Canadian results of operations were lower $50.1 million in the 2017 quarter compared to the 2016 period due to non-recurring 2016 income tax benefits associated with divestiture of Montney midstream assets in 2016 and a gain on sale of its synthetic operations completed in the second quarter 2016, and higher average sales prices received in 2017 for both oil and natural gas. Natural gas sales volumes increased in 2017 due to new production in the Kaybob and Placid areas of Western Canada. Impairment expense of $95.1 million was recorded in 2016 due to a write down of heavy oil properties at Seal in Western Canada and the Terra Nova field offshore East Coast Canada in 2016, as a result of weak oil sales prices.

Malaysia E&P operations reported earnings of $47.7 million in both the 2017 and 2016 quarters. Results were flat to 2016 in Malaysia as higher average oil and natural gas prices realized, lower lease operating and depreciation expenses and higher natural gas volume sold in Sarawak, essentially offset lower oil volume sold. Crude oil sales volumes in Malaysia were lower in the 2017 quarter, primarily due to natural field decline, while natural gas sales volume improved due to higher demand and less unplanned downtime versus the 2016 period. Depreciation expense was $5.7 million lower in 2017 compared to the 2016 quarter primarily due to lower volumes sold in Block K and lower unit rates in Sarawak, partially offset by higher sales volume in Sarawak and higher unit rates in Sabah.

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

Second quarter 2017 vs. 2016 (Contd.)

Other international E&P operations reported a gain of $7.2 million in the second quarter of 2017 compared to a loss of $5.1 million in the 2016 quarter. The $12.3 million improvement in the 2017 period was primarily related to lower dry hole cost, lower selling and general expenses resulting from restructuring activity in 2016 and higher income tax benefits on investments in foreign areas in 2017.

Total hydrocarbon production averaged 162,857 barrels of oil equivalent per day in the 2017 second quarter, which represented a 3.4% decrease from the 168,642 barrels of oil equivalents per day produced in the 2016 quarter. When Seal and Syncrude are excluded, the Company's worldwide production was flat in 2017 compared to 2016. Average crude oil and condensate production was 89,033 barrels per day in the second quarter of 2017 compared to 98,995 barrels per day in the second quarter of 2016. Crude oil production decreased in the Eagle Ford Shale area of South Texas in 2017 due to production decline associated with significantly less drilling in 2016 resulting from lower commodity prices. Crude oil production in the Gulf of Mexico was lower in the 2017 quarter due to well decline and unplanned downtime, partly offset by higher production at Kodiak, which started late in the first quarter of 2016. Heavy oil production from the Seal area in Western Canada was divested in mid-January 2017. Onshore oil production in Canada improved in the 2017 quarter in the Company's Kaybob and Placid areas acquired in the second quarter of 2016. Oil production offshore Eastern Canada was higher during 2017 primarily due to improved uptime at both Hibernia and Terra Nova fields. Lower oil production in 2017 in Malaysia was primarily attributable to less net oil volumes produced in Block K due to well decline and slightly lower entitlement percentage. On a worldwide basis, the Company's crude oil and condensate prices averaged $48.47 per barrel in the second quarter 2017 compared to $44.42 per barrel in the 2016 period, an increase of 9% quarter to quarter.

Total production of natural gas liquids (NGL) was 9,374 barrels per day in the 2017 second quarter compared to 8,883 barrels per day in the same 2016 period. The increase in NGL production was primarily associated with higher natural gas liquids volumes in the U.S. and Sarawak, Malaysia. The average sales price for U.S. NGL was $14.23 per barrel in the 2017 quarter compared to $11.33 per barrel in 2016. Average NGL prices in Malaysia in the second quarter of 2017 and 2016 were $52.68 per barrel and $34.62 per barrel, respectively.

Natural gas sales volumes averaged 387 million cubic feet per day in the second quarter 2017 compared to 365 million cubic feet per day in 2016. Natural gas sales volumes increased in North America for 2017 due primarily to new volumes in the Kaybob and Placid areas of Western Canada acquired in the second quarter of 2016, offset in part by lower volumes produced both offshore Gulf of Mexico and in Eagle Ford Shale. Natural gas production volumes in Malaysia increased in the 2017 period due to both higher demand and less downtime in the current period. North American natural gas sales prices averaged $2.15 per thousand cubic feet (MCF) in the 2017 quarter, 59% above the $1.35 per MCF average in the same quarter of 2016. The average realized price for natural gas produced in the 2017 quarter at fields offshore Sarawak was $3.57 per MCF, compared to a price of $3.29 per MCF in the 2016 quarter.

Six months 2017 vs. 2016

United States E&P operations reported earnings of $31.0 million in the first half of 2017 compared to a loss of $131.4 million in the 2016 period, an improvement of $162.4 million in 2017 compared to the 2016 period. Revenue in the U.S. was $182.5 million higher in the period as higher oil and natural gas realized sales prices more than offset lower sales volume. Lease operating expenses decreased by $17.8 million primarily due to lower costs in Eagle Ford Shale and Gulf of Mexico mainly related to cost structure improvements coupled with lower variable costs based on volumes produced. Depreciation expense decreased $41.5 million in 2017 compared to 2016 due to lower unit rates in the Gulf of Mexico in the 2017 period and lower U.S. volume sold. Exploration expenses were down $2.3 million in the 2017 period primarily related to lower undeveloped lease amortization expense compared to the first half of 2016.

Canadian E&P operations reported earnings of $105.8 million in the first half of 2017 compared to a loss of $31.9 million in the 2016 six months. Canadian results of operations improved by $137.7 million in the 2017 period. Results for conventional operations improved by $185.6 million in 2017 due to a gain of $96.0 million on sale of Seal heavy oil assets in 2017, lower impairment expense and higher average realized sales prices for crude oil and natural gas, partially offset by lower oil volume sold and higher lease operating expense. These were partially offset by higher production costs and no repeat of income tax benefits recognized on the sale of certain Montney midstream assets in 2016. Lease operating expenses associated with conventional operations were $5.4 million higher in the first six months of 2017 due to new wells online at Tupper in 2017

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

Six months 2017 vs. 2016 (Contd.)

and full six months production at Kaybob and Placid in 2017 versus two months in the first half of 2016. Impairment expense was $95.1 million in 2016, as low oil prices led to a write down of heavy oil properties at Seal in Western Canada and the Terra Nova field offshore East Coast Canada in the first quarter of the year. Synthetic operations in Canada were divested in the second quarter of 2016.

Malaysia E&P operations reported earnings of $106.3 million in the first half of 2017 compared to earnings of $70.1 million during the same period in 2016. Results improved $36.2 million in 2017 in Malaysia primarily due to higher realized oil sales prices at Block K, partially offset by lower oil sales volume due to normal field decline. Revenue improved by $35.1 million driven by higher commodity prices received and higher natural gas volume sold in Sarawak, partially offset by lower oil volume sold. Depreciation expense was $11.9 million lower in 2017 compared to the same period in 2016 primarily due to lower unit rates in Sarawak and lower oil volume sold, partly offset by higher natural gas volume sold in Sarawak and higher unit rates in Sabah.

Other international E&P operations reported a profit of $0.1 million in the first six months of 2017 compared to a loss of $31.2 million in the 2016 period. The 2017 period included lower dry hole costs of $10.7 million, with the higher 2016 costs primarily associated with unsuccessful drilling in Block 11-2/11 in Vietnam. The 2017 period also included income tax benefits on investments in foreign areas of $32.4 million. Other exploration expenses were $3.5 million higher in the current year, mostly attributable to costs in Mexico and Vietnam. Other expenses were $8.9 million higher in the 2017 period primarily related to no repeat of an adjustment of previously recorded exit costs in 2016 in the Republic of Congo.

Total worldwide production averaged 166,021 barrels of oil equivalent per day during the six months ended June 30, 2017, a 9.1% decrease from 182,604 barrels of oil equivalent produced in the same period in 2016. When Seal and Syncrude are excluded, the Company’s worldwide production decreased by 2.8%. Crude oil and condensate production in the first half of 2017 averaged 92,300 barrels per day compared to 111,235 barrels per day a year ago. Crude oil production decreased 5,153 barrels per day in the Eagle Ford Shale in 2017 due to production decline associated with significantly less drilling in 2016 in response to lower prices and phasing of capital expenditures into late 2017. Heavy oil production in Canada declined in 2017 in the Seal area of Western Canada primarily due to divestment of the asset in January 2017. Synthetic oil production in Canada also was nil in 2017 due to the Company’s divestiture of Syncrude Canada Ltd. in the second quarter of 2016. Lower oil production in 2017 in Block K Malaysia was primarily attributable to natural well decline. For the first six months of 2017, the Company’s sales price for crude oil and condensate averaged $49.17 per barrel, up from $38.78 per barrel in 2016.

Total production of natural gas liquids was 9,145 barrels per day in the 2017 period compared to 9,058 barrels per day in 2016. The sales price for U.S. natural gas liquids averaged $15.53 per barrel in 2017 compared to $9.80 per barrel in 2016.

Natural gas sales volumes increased from 374 million cubic feet per day in 2016 to 387 million cubic feet per day in 2017. Natural gas sales volume increased, primarily due to less unplanned downtime in 2017 in both Sarawak and Block K Malaysia. North American natural gas volume was flat as improvement in Canada due to the full year volumes from Kaybob and Placid fields were offset in part by lower U.S. volume due to natural field decline. The average sales price for North American natural gas in the first six months of 2017 was $2.17 per MCF, up from $1.45 per MCF realized in 2016. Natural gas production at fields offshore Sarawak was sold at an average realized price of $3.49 per MCF in 2017 compared to $3.52 per MCF in 2016.

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.)

Selected operating statistics for the three-month and six-month periods ended June 30, 2017 and 2016 follow.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Net crude oil and condensate produced – barrels per day	89,033	98,995	92,300	111,235
United States – Eagle Ford Shale	33,195	34,563	33,397	38,550
– Gulf of Mexico and other	11,329	12,564	11,844	13,331
Canada – onshore	3,051	950	2,470	540
– offshore	8,199	7,217	9,053	8,020
– heavy1	–	2,200	303	2,759
– synthetic1	–	3,093	–	9,326
Malaysia – Sarawak	13,176	13,944	13,346	13,490
– Block K	20,083	24,464	21,887	25,219
Net crude oil and condensate sold – barrels per day	86,851	96,918	88,361	108,054
United States – Eagle Ford Shale	33,195	34,563	33,397	38,550
– Gulf of Mexico and other	11,329	12,564	11,844	13,331
Canada – onshore	3,051	950	2,470	540
– offshore	8,938	7,315	8,463	8,348
– heavy1	–	2,200	303	2,759
– synthetic1	–	3,093	–	9,326
Malaysia – Sarawak	13,495	9,666	13,486	11,712
– Block K	16,843	26,567	18,398	23,488
Net natural gas liquids produced – barrels per day	9,374	8,883	9,145	9,058
United States – Eagle Ford Shale	6,921	6,751	6,884	6,988
– Gulf of Mexico and other	880	1,468	996	1,347
Canada	457	164	359	88
Malaysia – Sarawak	1,116	500	906	635
Net natural gas liquids sold – barrels per day	8,902	9,339	9,140	9,550

United States – Eagle Ford Shale	6,921	6,751	6,884	6,988
– Gulf of Mexico	880	1,468	996	1,347
Canada	457	164	359	88
Malaysia – Sarawak	644	956	901	1,127
Net natural gas sold – thousands of cubic feet per day	386,700	364,582	387,457	373,864
United States – Eagle Ford Shale	34,835	36,113	34,583	37,203
– Gulf of Mexico and other	11,625	16,779	11,868	20,094
Canada	220,171	204,753	218,641	207,288
Malaysia – Sarawak	112,993	96,057	114,767	97,155
– Block K	7,076	10,880	7,598	12,124
Total net hydrocarbons produced – equivalent barrels per day2	162,857	168,642	166,021	182,604
Total net hydrocarbons sold – equivalent barrels per day2	160,203	167,021	162,077	179,915

1 The Company sold the Seal area heavy oil field in January 2017 and its 5% non-operated interest in Syncrude Canada Ltd. in June 2016.

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 June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Weighted average sales prices				
Crude oil and condensate – dollars per barrel				
United States – Eagle Ford Shale	$ 48.11	43.95	48.38	38.93
– Gulf of Mexico	47.44	43.41	47.34	39.00
Canada1 – onshore	42.04	39.35	43.98	33.74
– offshore	48.93	44.51	50.07	36.82
– heavy2	–	18.03	25.12	11.83
– synthetic2	–	45.78	–	35.58
Malaysia – Sarawak3	48.89	47.22	51.72	41.74
– Block K3	50.44	46.53	50.59	41.97
Natural gas liquids – dollars per barrel				
United States – Eagle Ford Shale	$ 14.14	11.21	15.27	9.65
– Gulf of Mexico	14.93	11.89	17.29	10.59
Canada1	22.50	30.18	22.32	29.38
Malaysia – Sarawak3	52.68	34.62	51.05	35.65
Natural gas – dollars per thousand cubic feet				
United States – Eagle Ford Shale	$ 2.59	1.38	2.56	1.43
– Gulf of Mexico	2.62	1.46	2.59	1.62
Canada1	2.06	1.33	2.08	1.44
Malaysia – Sarawak3	3.57	3.29	3.49	3.52
– Block K	0.24	0.23	0.25	0.25

1 U.S. dollar equivalent.

2 The Company sold the Seal area heavy oil field in January 2017 and its 5% non-operated interest in Syncrude Canada Ltd. in June 2016.

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

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

OIL AND GAS OPERATING RESULTS – THREE MONTHS ENDED JUNE 30, 2017 AND 2016

(Millions of dollars)	United States	Canada Conven-tional	Synthetic	Malaysia	Other	Total
Three Months Ended June 30, 2017						
Oil and gas sales and other operating revenues	$ 239.5	88.2	–	176.5	–	504.2
Lease operating expenses	44.3	25.5	–	41.4	–	111.2
Severance and ad valorem taxes	10.4	0.3	–	–	–	10.7
Depreciation, depletion and amortization	135.5	46.0	–	48.3	1.0	230.8
Accretion of asset retirement obligations	4.2	1.9	–	4.3	–	10.4
Exploration expenses						
Dry holes	(1.0)	–	–	–	–	(1.0)
Geological and geophysical	0.6	–	–	–	0.1	0.7
Other	2.0	0.1	–	–	8.1	10.2
	1.6	0.1	–	–	8.2	9.9
Undeveloped lease amortization	10.2	0.1	–	–	–	10.3
Total exploration expenses	11.8	0.2	–	–	8.2	20.2
Selling and general expenses	16.6	7.0	–	3.3	5.0	31.9
Other expenses	3.6	–	–	2.8	–	6.4
Results of operations before taxes	13.1	7.3	–	76.4	(14.2)	82.6
Income tax provisions (benefits)	5.1	2.1	–	28.7	(21.4)	14.5
Results of operations (excluding corporate overhead and interest)	$ 8.0	5.2	–	47.7	7.2	68.1
Three Months Ended June 30, 2016						
Oil and gas sales and other operating revenues	$ 143.6	61.6	15.8	190.5	(0.1)	411.4
Lease operating expenses	54.5	25.0	31.8	45.2	–	156.5
Severance and ad valorem taxes	11.0	1.1	1.3	–	–	13.4
Depreciation, depletion and amortization	146.6	45.9	3.1	54.0	1.6	251.2
Accretion of asset retirement obligations	4.3	2.8	1.2	4.0	–	12.3
Exploration expenses						
Dry holes	(0.8)	–	–	4.5	10.7	14.4
Geological and geophysical	0.3	–	–	0.2	–	0.5

Other	1.0	0.1	–	–	6.2	7.3
	0.5	0.1	–	4.7	16.9	22.2
Undeveloped lease amortization	13.7	1.0	–	–	0.2	14.9
Total exploration expenses	14.2	1.1	–	4.7	17.1	37.1
Selling and general expenses	12.7	8.1	0.2	5.0	9.1	35.1
Other expenses (benefits)	(0.1)	1.6	–	0.9	(9.9)	(7.5)
Results of operations before taxes	(99.6)	(24.0)	(21.8)	76.7	(18.0)	(86.7)
Income tax provisions (benefits)	(33.9)	(27.4)	(73.7)	29.0	(12.9)	(118.9)
Results of operations (excluding corporate overhead and interest)	$ (65.7)	3.4	51.9	47.7	(5.1)	32.2

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

OIL AND GAS OPERATING RESULTS – SIX MONTHS ENDED JUNE 30, 2017 AND 2016

(Millions of dollars)	United States	Canada Conven-tional	Synthetic	Malaysia	Other	Total
Six Months Ended June 30, 2017						
Oil and gas sales and other operating revenues	$ 500.8	306.1	–	373.9	–	1,180.8
Lease operating expenses	92.2	48.1	–	93.0	–	233.3
Severance and ad valorem taxes	21.1	0.9	–	–	–	22.0
Depreciation, depletion and amortization	273.8	90.5	–	96.2	1.9	462.4
Accretion of asset retirement obligations	8.4	3.9	–	8.7	–	21.0
Exploration expenses						
Dry holes	(1.3)	–	–	3.2	–	1.9
Geological and geophysical	0.9	0.1	–	–	4.6	5.6
Other	4.0	0.1	–	–	17.0	21.1
	3.6	0.2	–	3.2	21.6	28.6
Undeveloped lease amortization	19.0	1.3	–	–	–	20.3
Total exploration expenses	22.6	1.5	–	3.2	21.6	48.9
Selling and general expenses	32.2	14.2	–	5.7	9.9	62.0
Other expenses	0.7	–	–	7.8	–	8.5
Results of operations before taxes	49.8	147.0	–	159.3	(33.4)	322.7
Income tax provisions (benefits)	18.8	41.2	–	53.0	(33.5)	79.5
Results of operations (excluding corporate overhead and interest)	$ 31.0	105.8	–	106.3	0.1	243.2
Six Months Ended June 30, 2016						
Oil and gas sales and other operating revenues	$ 318.3	119.2	64.3	338.8	–	840.6
Lease operating expenses	110.0	42.7	69.8	93.1	–	315.6
Severance and ad valorem taxes	21.4	2.2	2.5	–	–	26.1
Depreciation, depletion and amortization	315.3	90.8	16.5	108.1	3.0	533.7
Accretion of asset retirement obligations	8.6	5.4	2.4	8.1	–	24.5

Impairment of properties	–	95.1	–	–	–	95.1
Exploration expenses						
Dry holes	(0.5)	–	–	4.1	10.7	14.3
Geological and geophysical	0.6	2.9	–	0.5	4.3	8.3
Other	2.1	0.4	–	–	13.5	16.0
	2.2	3.3	–	4.6	28.5	38.6
Undeveloped lease amortization	22.7	2.3	–	–	0.4	25.4
Total exploration expenses	24.9	5.6	–	4.6	28.9	64.0
Selling and general expenses	35.2	15.7	0.5	8.4	19.2	79.0
Other expenses (benefits)	0.1	–	–	0.9	(8.9)	(7.9)
Results of operations before taxes	(197.2)	(138.3)	(27.4)	115.6	(42.2)	(289.5)
Income tax provisions (benefits)	(65.8)	(58.5)	(75.3)	45.5	(11.0)	(165.1)
Results of operations (excluding corporate overhead and interest)	$ (131.4)	(79.8)	47.9	70.1	(31.2)	(124.4)

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

Results of Operations (Contd.)

Corporate

Corporate activities, which include interest income and expense, foreign exchange effects, and corporate overhead not allocated to operating functions, had net cost of $85.5 million in the 2017 second quarter compared to $29.3 million in the same 2016 quarter. The $56.2 million increased cost in the 2017 period is primarily due to foreign currency exchange losses in the 2017 period versus gains in the 2016 period, deferred tax charges on undistributed earnings of certain foreign subsidiaries in 2017 and higher net interest expense in 2017, partially offset by lower administrative costs in the current quarter. An after-tax loss of $31.1 million occurred in 2017 on transactions denominated in foreign currencies, while the 2016 quarter had an after-tax gain of $19.5 million. Net interest costs increased $10.7 million in the 2017 period primarily due to issuance of $550 million in notes in August 2016, which 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. Selling and general expenses decreased $6.6 million in the second quarter of 2017 primarily related to restructuring activity that occurred in 2016 and continual monitoring of the cost structure.

During the first six months of 2017, Corporate activities had a net cost of $203.1 million compared to $72.2 million for the same period of 2016. The $130.9 million increased cost in the 2017 period compared to the 2016 period was primarily due to losses from foreign exchange effects in the 2017 period versus gains in the 2016 period, higher net interest expense and deferred tax charges in 2017 on undistributed earnings of certain foreign subsidiaries and higher net interest expense in the later period due to issuance of $550 million in notes in 2016 and an increase of 1.00% on the coupon rates on $1.5 billion of the Company’s notes; these were partially offset by lower administrative costs in 2017. During the first six months of 2017, the Company’s determined that prospective earnings from its Malaysian and Canadian subsidiaries will not be considered reinvested into local operations. Due to this change in assertion, the Company recorded a deferred tax charge of $60.4 million in the first six months of 2017 associated with the estimated tax consequence of the future repatriation of these subsidiaries’ six-months 2017 earnings. This decision provides greater financial flexibility as it considers future domestic investment opportunities. The Company expects to incur further tax charges in future 2017 quarters for additional 2017 foreign earnings as they arise.

Discontinued Operations

The Company has presented its former U.K. refining and marketing operations as discontinued operations in its consolidated financial statements. The after-tax results of these operations for the three-month and six-month periods ended June 30, 2017 and 2016 are reflected in the following table.

(Millions of dollars)		Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
U.K. refining and marketing	$	(0.2)	(1.7)	0.8	(0.1)
U.K. exploration and production		–	1.7	–	0.8
Income from discontinued operations - U.K. refining and marketing	$	(0.2)	–	0.8	0.7

Financial Condition

Net cash provided by continuing operating activities was $591.5 million for the first six months of 2017 compared to $113.4 million during the same period in 2016. The improvement in cash provided by continuing operations activities in 2017 was primarily attributable to higher realized sales prices for the Company’s oil and gas production, lower lease operating and administrative expenses and rig cancellation payments discussed below, partially offset by lower volume sold in the current year and higher interest costs. Changes in operating working capital from continuing operations increased cash by $42.6 million during the first six months of 2017, compared to a use of cash of $86.8 million in 2016. The use of cash in 2016 included $253.2 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 $64.3 million in 2017 primarily relating to proceeds from the sale of the Seal field in Western Canada while the 2016 period generated cash of $1,153.3 million mainly related to the sale of Syncrude Canada Limited and certain midstream assets in the Tupper area of Western Canada. Other significant sources of cash included $284.2 million in the 2017 period and $701.4 million in 2016 from maturity of Canadian government securities that had maturity dates greater than 90 days at acquisition.

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

Financial Condition (Contd.)

Cash used for property additions and dry holes, which including amounts expensed, were $431.7 million and $604.6 million in the six-month period ended June 30, 2017 and 2016, respectively. Total cash dividends to shareholders amounted to $86.3 million in 2017 and $120.5 million in 2016. The purchase of Canadian government securities with maturity dates greater than 90 days at acquisition used cash of $212.7 million in the 2017 period and $651.2 million in the 2016 period. The Company repaid debt in the amount of $600.0 million in the six-month period of 2016 using proceeds from the sale of assets.

Total accrual basis capital expenditures were as follows:

(Millions of dollars)	Six Months Ended June 30, 2017	2016
Capital Expenditures		
Exploration and production	$ 411.2	442.9
Corporate	3.8	20.7
Total capital expenditures	$ 415.0	463.6

The decrease in capital expenditures in the exploration and production business in 2017 compared to 2016 was primarily attributable to lower acquisition costs in the Kaybob Duvernay and liquids rich Montney properties in Canada and lower spending in Malaysia, partially offset by higher development drilling in the Eagle Ford Shale area in the United States.

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

(Millions of dollars)	Six Months Ended June 30, 2017	2016

Property additions and dry hole costs per cash flow statements	$ 431.7	604.6
Geophysical and other exploration expenses	26.7	24.3
Capital expenditure accrual changes and other	(43.4)	(165.3)
Total capital expenditures	$ 415.0	463.6

Working capital (total current assets less total current liabilities) at June 30, 2017 was $182.9 million, $126.2 million more than December 31, 2016, with the increase primarily attributable to higher cash balances and lower accounts payable. Included in working capital at both period ends is $550 million of bonds maturing in December 2017.

At June 30, 2017, long-term debt of $2,367.1 million had decreased by $55.7 million compared to December 31, 2016. A summary of capital employed at June 30, 2017 and December 31, 2016 follows.

	June 30, 2017		December 31, 2016	
(Millions of dollars)	Amount	%	Amount	%
Capital employed				
Long-term debt	$ 2,367.1	32.2 %	$ 2,422.8	33.0 %
Stockholders' equity	4,977.7	67.8 %	4,916.7	67.0 %
Total capital employed	$ 7,344.8	100.0 %	$ 7,339.5	100.0 %

Cash and invested cash are maintained in several operating locations outside the United States. At June 30, 2017, Cash and cash equivalents and cash temporarily invested in Canadian government securities held outside the U.S. included U.S. dollar equivalents of approximately $360.9 million in Canada and $358.7 million in Malaysia. In addition $13.1 million of cash was held in the United Kingdom, but was reflected in current Assets Held for Sale on the Company's Consolidated Balance Sheet at June 30, 2017. 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 incentivize 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. See the "Corporate" section on page 29 regarding the Company's change in assertion for indefinite reinvestment on prospective earnings from its Malaysian and Canadian subsidiaries.

Accounting and Other Matters

Business Combinations

In January 2017, the FASB issued an ASU update to clarify the definition of a business with the objective of adding guidance to assist entities in evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The standard is intended to narrow the definition of a business by specifying the minimum inputs and processes and by narrowing the definition of outputs. The update is effective for annual and interim periods beginning in 2018 and is required to be adopted using a prospective approach, with early adoption permitted for transactions not previously reported in issued financial statements. The Company adopted this guidance in 2017 and it did not have a material impact on its consolidated financial statements and footnote disclosures

Compensation-Stock Compensation

In March 2016, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (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. The Company adopted this guidance in 2017 and it did not have a material impact on its consolidated financial statements and footnote disclosures as there were no exercises of Company options during the period.

Compensation – Retirement Benefits

In March 2017, the FASB issued an update requiring that the service cost component of pension and postretirement benefit costs be presented in the same line item as other current employee compensation costs and other components of those benefit costs be presented separately from the service cost component and outside a subtotal of income from operations, if presented. The update also requires that only the service cost component of pension and postretirement benefit cost is eligible for capitalization. The update is effective for annual periods beginning after December 15, 2017 and interim periods within the annual period. Application is retrospective for the presentation of the components of these benefit costs and prospective for the capitalization of only service costs. Early adoption is permitted. The Company does not believe the application of this accounting standard will have a material impact on its consolidated financial statements.

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 ASU's 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. Additional disclosures will be required to describe the nature, amount, timing and uncertainly of revenue and cash flows from contracts with customers. 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 is performing an initial review of contracts in each of its revenue streams and is developing accounting policies to address the provisions of the ASU. While the Company does not currently expect net earnings to be materially impacted, the Company is analyzing whether total revenues and expenses will be significantly impacted. The Company continues to evaluate the impact of this and other provisions of the ASU's on its accounting policies, internal controls, and consolidated financial statements and related disclosures, and has not finalized any estimates of the potential impacts. The Company will adopt the new standard on January 1, 2018, using the modified retrospective method with a cumulative adjustment to retained earnings as necessary.

Leases

In February 2016, FASB issued an 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 right-of-use 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 analyzing its portfolio of contracts to assess the impact future adoption of this ASU may have on its consolidated financial statements.

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

Accounting and Other Matters (Contd.)

Statement of Cash Flows

In August 2016, the FASB issued an ASU to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. The amendment provides guidance on specific cash flow issues including debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instrument 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. The ASU is effective for annual and interim periods beginning after December 15, 2017. The Company is currently assessing the potential impact of this ASU on its consolidated financial statements.

Outlook

Average worldwide crude oil prices in July 2017 have slightly declined from the average prices during the second quarter of 2017. North American natural gas prices decreased slightly in July from the 2017 second quarter. The Company expects its total oil and natural gas production to average 156,000 to 158,000 barrels of oil equivalent per day in the third quarter 2017. The Company currently anticipates total capital expenditures for the full year 2017 to be approximately $890 million.

The Company will primarily fund its capital program in 2017 using operating cash flow, but will supplement funding where necessary using borrowings under available credit facilities. The Company has $550 million of 2.5% notes that mature in December 2017. If oil and/or natural gas prices weaken, actual cash flow generated from operations could be reduced such that capital spending reductions are required and/or additional borrowings might be required during the year to maintain funding of the Company’s ongoing development projects.

As of August 1, 2017, the Company has entered derivative or forward fixed-price delivery contracts to manage risk associated with certain future oil and natural gas sales prices as follows:

Commodities	Contract or Location	Dates	Average Volumes per Day	Average Prices
U.S. Oil	West Texas Intermediate	July – Dec. 2017	22,000 bbls/d	$50.41 per bbl.

Canadian Natural Gas	TCPL–NOVA System	July – Dec. 2017	124 mmcf/d	C$2.97 per mcf
Canadian Natural Gas	TCPL–NOVA System	Jan 2018 – Dec 2020	59 mmcf/d	C$2.81 per mcf
Natural Gas	Alberta Alliance	Nov 2017 – Mar 2018	20 mmcf/d	US$3.51 per mcf *

*Title transfer at Alberta Alliance pipeline. Sale price fixed and transported to Chicago Gate.

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 2016 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 June 30, 2017 covering certain future U.S. crude oil sales volumes in 2017. A 10% increase in the respective benchmark price of these commodities would have decreased the recorded net receivable associated with these derivative contracts by approximately $18.9 million, while a 10% decrease would have increased the recorded net receivable by a similar amount.

There were no derivative foreign exchange contracts in place at June 30, 2017.

ITEM 4. CONTROLS AND PROCEDURES

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

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

During the quarter ended June 30, 2017, 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 2016 Form 10-K filed on February 24, 2017. The Company has not identified any additional risk factors not previously disclosed in its 2016 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/ CHRISTOPHER D. HULSE
Christopher D. Hulse, Vice President
and Controller (Chief Accounting Officer
and Duly Authorized Officer)

August 2, 2017

(Date)

EXHIBIT INDEX

Exhibit No.	
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.