SYNOVUS FINANCIAL CORP
Form 8-K
May 29, 2013

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of

the Securities Exchange Act of 1934

May 29, 2013 (May 29, 2013)

Date of Report

(Date of Earliest Event Reported)

Synovus Financial Corp.

(Exact Name of Registrant as Specified in its Charter)

Georgia	**1-10312**	**58-1134883**
(State of Incorporation)	**(Commission File Number)**	**(IRS Employer Identification No.)**

1111 Bay Avenue, Suite 500, Columbus, Georgia 31901

(Address of principal executive offices) (Zip Code)

(706) 649-2311

(Registrant s telephone number, including area code)

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

¨ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

¨ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

¨ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

¨ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events

As previously disclosed, in 2010, Synovus Bank (the Bank) entered into a Memorandum of Understanding (the Bank MOU) with the Georgia Department of Banking and Finance (the GA DBF) and the Federal Deposit Insurance Corporation (the FDIC and, together with the GA DBF, the Supervisory Authorities). The Supervisory Authorities have terminated the Bank MOU effective as of May 29, 2013. The Bank MOU will be replaced with a resolution adopted by the Bank s Board of Directors relating to, among other things, continued emphasis on improving asset quality and maintaining strong levels of capital and liquidity.

Signature

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, Synovus has caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

SYNOVUS FINANCIAL CORP.
(Synovus)

Dated: May 29, 2013

By: /s/Samuel F. Hatcher
Samuel F. Hatcher
Executive Vice President,

General Counsel and Secretary

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New Roman;font-size:9pt;text-align:right;" nowrap="nowrap">1,315,355

1,371,603

Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $12,625,179 in 2018 and $12,280,741 in 2017

8,208,142

8,220,031

Deferred income taxes

370,641

211,543

Deferred charges and other assets

51,311

57,765

Total assets

$

9,945,449

9,860,942

LIABILITIES AND STOCKHOLDERS' EQUITY

Current liabilities

Current maturities of long-term debt

$

9,674

9,902

Accounts payable

632,072

595,916

Income taxes payable

91,072

44,604

Other taxes payable

18,683

23,574

Other accrued liabilities

148,910

156,681

Liabilities associated with assets held for sale

3,146

3,530

Total current liabilities

903,557

834,207

Long-term debt, including capital lease obligation

2,897,345

2,906,520

Deferred income taxes

127,350

159,098

Asset retirement obligations

693,300

709,299

Deferred credits and other liabilities

652,259

631,627

Stockholders' equity

Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued

–

–

Common Stock, par $1.00, authorized 450,000,000 shares, issued
195,065,341 shares in 2018 and 195,055,724 in 2017

195,065

195,056

Capital in excess of par value

898,126

917,665

Retained earnings

5,402,732

5,245,242

Accumulated other comprehensive loss

(575,123)

(462,243)

Treasury stock

(1,249,162)

(1,275,529)

Total stockholders’ equity

4,671,638

4,620,191

Total liabilities and stockholders’ equity

$

9,945,449

9,860,942

See Notes to Consolidated Financial Statements, page 7.

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Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF OPERATIONS (unaudited)

(Thousands of dollars, except per share amounts)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2018	2017 1	2018	2017 1
Revenues				
Revenue from sales to customers	$ 655,150	477,560	1,262,104	986,595
(Loss) gain on crude contracts	(37,624)	26,861	(67,126)	63,938
Gain on sale of assets and other income	668	3,858	8,821	134,386
Total revenues	618,194	508,279	1,203,799	1,184,919
Costs and expenses				
Lease operating expenses	136,589	111,179	273,085	233,321
Severance and ad valorem taxes	12,876	10,742	25,033	21,955
Exploration expenses, including undeveloped lease amortization	19,145	20,201	48,073	48,864
Selling and general expenses	57,800	52,809	109,217	102,774
Depreciation, depletion and amortization	237,997	234,992	468,730	471,146
Accretion of asset retirement obligations	11,028	10,428	20,942	20,984
Other expense (benefit)	659	6,377	(10,389)	8,534
Total costs and expenses	476,094	446,728	934,691	907,578
Operating income from continuing operations	142,100	61,551	269,108	277,341
Other income (loss)				
Interest and other income (loss)	(15,051)	(38,305)	33	(54,616)
Interest expense, net	(44,723)	(45,145)	(89,772)	(89,742)
Total other loss	(59,774)	(83,450)	(89,739)	(144,358)
Income (loss) from continuing operations before income taxes	82,326	(21,899)	179,369	132,983
Income tax expense (benefit)	36,410	(4,545)	(35,237)	92,842
Income (loss) from continuing operations	45,916	(17,354)	214,606	40,141
Income (loss) from discontinued operations, net of income taxes	(398)	(217)	(835)	752
NET INCOME (LOSS)	$ 45,518	(17,571)	213,771	40,893
INCOME (LOSS) PER COMMON SHARE – BASIC				
Continuing operations	$ 0.26	(0.10)	1.25	0.23

Discontinued operations	-	-	(0.01)	0.01
Net Income (Loss)	$ 0.26	(0.10)	1.24	0.24
INCOME (LOSS) PER COMMON SHARE – DILUTED				
Continuing operations	$ 0.26	(0.10)	1.23	0.23
Discontinued operations	-	-	(0.01)	0.01
Net Income (Loss)	$ 0.26	(0.10)	1.22	0.24
Cash dividends per Common share	0.25	0.25	0.50	0.50
Average Common shares outstanding (thousands)				
Basic	173,043	172,558	172,907	172,482
Diluted	173,983	172,558	174,927	173,017

1 Reclassified to conform to current presentation (see Notes A and B).

See Notes to Consolidated Financial Statements, page 7.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (unaudited)

(Thousands of dollars)

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Net income	$ 45,518	(17,571)	213,771	40,893
Other comprehensive income (loss), net of tax				
Net (loss) gain from foreign currency translation	(34,910)	70,220	(87,185)	92,884
Retirement and postretirement benefit plans	3,938	2,386	7,108	4,773
Deferred loss on interest rate hedges reclassified to interest expense	586	481	1,171	963
Reclassification of certain tax effects to retained earnings	–	–	(30,237)	–
Other	–	–	(3,737)	–
Other comprehensive (loss) income	(30,386)	73,087	(112,880)	98,620
COMPREHENSIVE INCOME	$ 15,132	55,516	100,891	139,513

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,	
	2018	2017
Operating Activities		
Net income	$ 213,771	40,893
Adjustments to reconcile net income to net cash provided by continuing operations activities:		
Loss (Income) from discontinued operations	835	(752)
Depreciation, depletion and amortization	468,730	471,146
Dry hole costs (credits)	(11)	1,904
Amortization of undeveloped leases	22,774	20,306
Accretion of asset retirement obligations	20,942	20,984
Deferred income tax (benefit) charge	(156,489)	33,130
Pretax (gain) loss from disposition of assets	118	(130,648)
Net decrease in noncash operating working capital	85,440	42,581
Other operating activities, net	(31,564)	91,918
Net cash provided by continuing operations activities	624,546	591,462
Investing Activities		
Property additions and dry hole costs	(615,144)	(431,654)
Proceeds from sales of property, plant and equipment	623	64,303
Purchases of investment securities 1	–	(212,661)
Proceeds from maturity of investment securities 1	–	284,193
Net cash required by investing activities	(614,521)	(295,819)
Financing Activities		
Capital lease obligation payments	(4,648)	(11,983)
Withholding tax on stock-based incentive awards	(6,922)	(7,081)
Cash dividends paid	(86,517)	(86,278)
Net cash required by financing activities	(98,087)	(105,342)
Effect of exchange rate changes on cash and cash equivalents	24,382	(4,611)
Net increase (decrease) in cash and cash equivalents	(63,680)	185,690
Cash and cash equivalents at beginning of period	964,988	872,797

Cash and cash equivalents at end of period	$ 901,308	1,058,487

1 Investments 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, 2018	2017
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	$ –	–
Common Stock – par $1.00, authorized 450,000,000 shares, issued 195,065,341 shares at June 30, 2018 and 195,055,724 shares at June 30, 2017		
Balance at beginning of period	195,056	195,056
Exercise of stock options	9	–
Balance at end of period	195,065	195,056
Capital in Excess of Par Value		
Balance at beginning of period	917,665	916,799
Exercise of stock options, including income tax benefits	(175)	–
Restricted stock transactions and other	(32,766)	(26,483)
Stock-based compensation	13,402	13,302
Other	–	(76)
Balance at end of period	898,126	903,542
Retained Earnings		
Balance at beginning of period	5,245,242	5,729,596
Net income for the period	213,771	40,893
Reclassification of certain tax effects from accumulated other comprehensive loss	30,237	–
Cash dividends	(86,518)	(86,278)
Balance at end of period	5,402,732	5,684,211
Accumulated Other Comprehensive Loss		
Balance at beginning of period	(462,243)	(628,212)
Foreign currency translation (loss) gain, net of income taxes	(87,185)	92,884
Retirement and postretirement benefit plans, net of income taxes	7,108	4,773
Deferred loss on interest rate hedges reclassified to interest expense, net of income taxes	1,171	963
Reclassification of certain tax effects to retained earnings	(30,237)	–
Other	(3,737)	–
Balance at end of period	(575,123)	(529,592)
Treasury Stock		
Balance at beginning of period	(1,275,529)	(1,296,560)
Sale of stock under employee stock purchase plan	–	145

Awarded restricted stock, net of forfeitures	26,367	20,886
Balance at end of period – 22,018,095 shares of Common Stock in 2018 and 22,482,581 shares of Common Stock in 2017, at cost	(1,249,162)	(1,275,529)
Total Stockholders’ Equity	$ 4,671,638	4,977,688

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, 2018 and December 31, 2017, and the results of operations, cash flows and changes in stockholders' equity for the interim periods ended June 30, 2018 and 2017, 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 2017 Form 10-K report, as certain notes and other pertinent information have been abbreviated or omitted in this report. Financial results for the six-month period ended June 30, 2018 are not necessarily indicative of future results.

Beginning in the period ended September 30, 2017, certain reclassifications in presentation have been made to the Consolidated Statements of Operations. The Company now presents a separate "Operating income (loss) from continuing operations" subtotal on the Consolidated Statements of Operations. Additionally, "Interest and other income (loss)," which includes foreign exchange gains and losses, has been reclassified from a component of total revenues and is now presented below Operating income (loss) from continuing operations. "Interest expense" and "Capitalized interest" have also been combined into the "Interest expense, net" line item and is now presented below "Operating income (loss) from continuing operations." Previously reported periods have been reclassified to conform to the current period presentation. These reclassifications did not impact previously reported Income from continuing operations before income taxes, Income from continuing operations, or Net income.

Note B – New Accounting Principles and Recent Accounting Pronouncements

Accounting Principles Adopted

Revenue from Contracts with Customers. In May 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU), which established a comprehensive model of accounting for revenue arising from contracts with customers that superseded most revenue recognition requirements and industry-specific guidance. Under the new standard, the Company recognizes revenue when it transfers control of the commodity to customers in an amount that reflects the consideration the Company expects to be entitled to in exchange for the commodity. Additional disclosures are required to describe the nature, amount, timing and uncertainly of revenue and cash flows from contracts with customers. The Company adopted the new standard in the first quarter of 2018 using the modified retrospective method. The Company performed a review of contracts in each of its revenue streams and implemented accounting policies and internal controls to address the requirements of the ASU. Prior to January 1, 2018, the Company followed the sales method of revenue recognition under Accounting Standards Codification (ASC) Topic 605 and recorded revenue when deliveries occured and legal ownership of the commodity transferred to the customer.

There was no adjustment to the opening balance of stockholders' equity as at January 1, 2018, resulting from application of the new ASU promulgated in ASC Topic 606 using the modified retrospective method. The comparative information has not been adjusted and continues to be reported under ASC Topic 605 – Revenue Recognition. See also Note C for further discussion of Revenue Recognition.

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 amendments in this ASU were effective for annual and interim periods beginning after December 15, 2017. The Company adopted this guidance in the first quarter of 2018 and it did not have a material impact on its consolidated financial statements.

Note B – New Accounting Principles and Recent Accounting Pronouncements (Contd.)

Accounting Principles Adopted (Cont.)

Compensation – Retirement Benefits. In March 2017, the FASB issued an ASU 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 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 and interim periods beginning after December 15, 2017. The Company adopted the standard in the first quarter of 2018 and it did not have a material impact on its consolidated financial statements.

Compensation – Stock Compensation. In May 2017, the 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. The Company adopted this accounting standard in the first quarter of 2018 and it did not have material impact on its consolidated financial statements.

Statement of Operations – Reporting Comprehensive Income. In February 2018, the FASB issued an ASU, which allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act. The Company elected to early adopt this accounting standard during the first quarter of 2018 and recorded discrete adjustments from accumulated other comprehensive income to retained earnings of $28.4 million related to retirement and postretirement obligations and $1.8 million related to deferred loss on interest rate derivative hedges. The adoption of this ASU will have no future impact.

Recent Accounting Pronouncements

Leases. In February 2016, the 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 assessing internal processes and analyzing its portfolio of contracts to assess the impact future adoption of this ASU will have on its consolidated financial statements.

Compensation – Stock Compensation. In June 2018, the FASB issued an ASU which supersedes existing guidance for equity-based payments to nonemployees and expands the scope of guidance for stock compensation to include all share-based payment arrangements related to the acquisition of goods and services from both nonemployees and employees. As a result, the same guidance that provides for employee share-based payments, including most of its requirements related to classification and measurement, applies to nonemployee share-based payment arrangements. The ASU 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. The Company anticipates adopting this guidance for the first quarter of 2019 and does not expect it to have a material impact on its consolidated financial statements.

Note C – Revenue from Contracts with Customers

Significant Accounting Policy

Revenue is recognized when the Company satisfies a performance obligation by transferring control over a commodity to a customer; the amount of revenue recognized reflects the consideration expected in exchange for those commodities. The Company measures revenue based on consideration specified in a contract and excludes taxes and other amounts collected on behalf of third parties.

Revenue is presented as Company share net of certain costs associated with generation of Revenue. Examples of costs that reduce revenue include transportation, gathering, compression, and processing fees in U.S. and Canada, as well as certain required payments associated with production sharing contracts (PSCs) and export taxes in Malaysia.

Nature of Goods and Services

The Company explores for and produces crude oil, natural gas and natural gas liquids (collectively oil and gas) worldwide. The Company's revenue from sales of oil and gas production activities are subdivided into three key geographic segments: the U.S., Canada, and Malaysia. Additionally, revenue from sales to customers is generated from three primary revenue streams: crude oil and condensate, natural gas liquids, and natural gas.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note C – Revenue from Contracts with Customers (Contd.)

For operated oil and gas production where the non-operated working interest owner does not take-in-kind its proportionate interest in the produced commodity, the Company acts as an agent for the working interest owner and recognizes revenue only for its own share of the commingled production.

U.S.- In the United States, the Company primarily produces oil and gas from fields in the Eagle Ford Shale area of South Texas and in the Gulf of Mexico. Revenue is generally recognized when oil and gas are transferred to the customer at the delivery point. Revenue recognized is largely index based with price adjustments for floating market differentials.

Canada- Primarily all long-term contracts in Canada, except for certain natural gas physical forward sales fixed-price contracts, are floating commodity index priced. For the Onshore business in Canada, the recorded revenue is net of transportation and any gain or loss on spot purchases made to meet committed volumes on sales contracts for the month. For the Offshore business in Canada, contracts are based on index prices and revenue is recognized at the time of vessel load based on the volumes on the bill of lading and point of custody transfer.

Malaysia- In Malaysia, the Company has interests in nine separate PSCs. The Company serves as the operator of all these areas except for the unitized Kakap-Gumusut field. Crude oil contracts in Malaysia share similar features of largely fixed cargo quantities, variable index-based pricing, and potential discounts at the point of meeting the performance obligation when the vessel is loaded. Malaysia also has three long term Gas Sales Agreements (GSA) with terms until the end of the field life, economic life, or PSC term.

Disaggregation of Revenue

The Company reviews performance based on three key geographical segments and between onshore and offshore sources of Revenue within these geographies.

For the three months ended June 30, 2018 and 2017, the Company recognized $655.2 million and $477.6 million, respectively, from contracts with customers for the sales of oil, natural gas liquids and natural gas. For the six months ended June 30, 2018 and 2017, the Company recognized $1,262.1 million and $986.6 million, respectively, from contracts with customers for the sales of oil, natural gas liquids and natural gas.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note C – Revenue from Contracts with Customers (Contd.)

		Three Months Ended		Six Months Ended	
		June 30,		June 30,	
(Thousands of dollars)		2018	2017	2018	2017
Net crude oil and condensate revenue					
United States – Onshore	$	198,823	143,684	381,472	293,671
– Offshore		94,393	47,669	165,922	101,481
Canada – Onshore		28,425	11,658	49,719	20,778
– Offshore		48,316	38,863	102,631	75,877
Malaysia – Sarawak		85,596	59,758	162,902	125,542
– Block K		101,609	76,741	196,181	164,572
Total crude oil and condensate revenue		557,162	378,373	1,058,827	781,921
Net natural gas liquids revenue					
United States – Onshore		13,236	9,077	25,370	18,724
– Offshore		2,920	1,209	4,559	3,125
Canada – Onshore		3,448	881	6,916	1,313
Malaysia – Sarawak		4,002	3,358	10,193	8,541
Total natural gas liquids revenue		23,606	14,525	47,038	31,703
Net natural gas revenue					
United States – Onshore		6,291	8,006	13,062	15,041
– Offshore		2,826	2,718	5,762	5,381
Canada – Onshore		28,089	37,951	67,683	77,798
Malaysia – Sarawak		36,997	35,829	69,380	74,418
– Block K		179	158	352	333
Total natural gas revenue		74,382	84,662	156,239	172,971
Total revenue from contracts with customers		655,150	477,560	1,262,104	986,595
Gain (loss) on crude contracts		(37,624)	26,861	(67,126)	63,938
Other operating income (loss)		448	5,191	8,939	3,738
Gain (loss) on sale of assets		220	(1,333)	(118)	130,648
Total revenue	$	618,194	508,279	1,203,799	1,184,919

Contract Balances and Asset Recognition

As of June 30, 2018, and December 31, 2017, receivables from contracts with customers, net of royalties and associated payables, on the balance sheet, were $190.7 million and $203.4 million, respectively. Payment terms for Murphy's sales vary across contracts and geographical regions, with the majority of the cash receipts required within 30 days of billing. Based on historical collections and ability of customers to pay, the Company did not recognize any impairment losses on receivables or contract assets arising from customer contracts during the reporting periods.

The Company has not entered into any upstream oil and gas sale contracts that have financing components as at June 30, 2018.

The Company does not employ sales incentive strategies such as commissions or bonuses for obtaining sales contracts. For the periods presented, the Company did not identify any assets to be recognized associated with the costs to obtain a contract with a customer.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note C – Revenue from Contracts with Customers (Contd.)

Performance Obligations

The Company recognizes oil and gas revenue when it satisfies a performance obligation by transferring control over a commodity to a customer. Judgment is required to determine whether some customers simultaneously receive and consume the benefit of commodities. As a result of this assessment for the Company, each unit of measure of the specified commodity is considered to represent a distinct performance obligation that is satisfied at a point in time upon the transfer of control of the commodity.

For contracts with market or index-based pricing, which represent the majority of Murphy's sales contracts, the Company has elected the allocation exception and allocates the variable consideration to each single performance obligation in the contract. As a result, there is no price allocation to unsatisfied remaining performance obligations for delivery of commodity product in subsequent periods.

The Company has entered into several long-term, fixed-price contracts in Canada. The underlying reason for entering a fixed price contract is generally unrelated to anticipated future prices or other observable data and serves a particular purpose in the company's long-term strategy. The contractually stated price for each unit of commodity transferred under these contracts represents the stand-alone selling price of the commodity.

As at June 30, 2018, the Company had the following sales contracts in place which are expected to generate revenue from sales to customers for a period of 12 months or more starting at the inception of the contract:

Current Long-Term Contracts Outstanding at June 30, 2018

Location	Commodity	End Date	Description	Approximate Volumes
U.S. Onshore	Oil	Q2 2019	Fixed quantity delivery in Eagle Ford	4,000 BOE/Day
U.S. Onshore	Oil	Q3 2019	Fixed quantity delivery in Eagle Ford	2,000 BOE/Day
U.S. Onshore	Oil	Q4 2021	Fixed quantity delivery in Eagle Ford	2018: 19,000 BOE/Day 2019-2021: 13,000 BOE/Day
U.S. Onshore	Gas and NGL	Q2 2026	Deliveries from dedicated acreage in Eagle Ford	As produced
Canada Onshore	Gas	Q4 2020	Contracts to sell natural gas at Alberta AECO Cdn dollar 2.81/MCF	59 MMCF/Day
Canada Onshore	Gas	Q4 2020	Contracts to sell natural gas at USD Index pricing	60 MMCF/Day
Canada Onshore	Gas	Q4 2024	Contracts to sell natural gas at USD Index pricing	30 MMCF/Day
Canada Onshore	Gas	Q4 2026	Contracts to sell natural gas at USD Index	38 MMCF/Day

pricing

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note D – Property, Plant and Equipment

Exploratory Wells

Under 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, 2018, the Company had total capitalized exploratory well costs pending the determination of proved reserves of $206.4 million. The following table reflects the net changes in capitalized exploratory well costs during the six-month periods ended June 30, 2018 and 2017.

(Thousands of dollars)	2018	2017
Beginning balance at January 1	$ 175,640	148,500
Additions pending the determination of proved reserves	30,731	48,764
Reclassifications to proved properties based on the determination of proved reserves	–	(13,370)
Capitalized exploratory well costs charged to expense	–	(8,360)
Balance at June 30	$ 206,371	175,534

There were no capitalized well costs charged to expense during the first six months of 2018. The capitalized well costs charged to expense during the first six months of 2017 included the Marakas-01 well in Block SK314A, offshore Malaysia, in which development of the well could not be justified due to noncommercial hydrocarbon quantities found.

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, 2018			2017		
(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	$ 34,779	2	2	$ 57,900	3	3
One to two years	35,934	2	1	53,023	3	3
Two to three years	50,272	2	2	–	–	–
Three years or more	85,386	7	1	64,611	6	–
	$ 206,371	13	6	$ 175,534	12	6

Of the $171.6 million of exploratory well costs capitalized more than one year at June 30, 2018, $70.4 million is in Brunei, $52.6 million is in Vietnam, $27.8 million is in the U.S. and $20.8 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.

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 $48.8 million. Additionally, the buyer assumed the asset retirement obligation of approximately $85.9 million. A $132.4 million pretax gain was reported in the 2017 period related to the sale. Also, in 2017, a U.S. subsidiary of the Company completed its disposition of certain non-core properties in the Eagle Ford Shale area. Total cash consideration to Murphy upon closing of the transaction was approximately $19.6 million. There were no gains or losses recorded related to these non-core Eagle Ford Shale sales.

In 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. Total cash consideration received upon closing was $414.1 million. A gain on sale of approximately $187.0 million was deferred and is being recognized over approximately the next 18 years in the Canadian operating segment. The Company amortized approximately $3.8 million and $3.4 million of the deferred gain during the first six months of 2018 and 2017, respectively. The remaining deferred gain of $170.2 million was included as a component of Deferred credits and other liabilities in the Company's Consolidated Balance Sheet as of June 30, 2018.

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

Acquisitions

In 2016, a Canadian subsidiary of Murphy Oil acquired a 70% operated working interest (WI) of Athabasca Oil Corporation's (Athabasca) production, acreage, infrastructure and facilities in the Kaybob Duvernay lands, and a 30% 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. As of June 30, 2018, $75.4 million of the carried interest had been paid. The carry is to be paid over a period up to 2021.

Other

In 2006, the Kakap field in Block K was unitized with the Gumusut field in an adjacent block under a Unitization and Unit Operating Agreement (UUOA) between the operators. The Gumusut-Kakap Unit is operated by another company. In the fourth quarter 2016, the operators completed the first redetermination process for a revision to the blocks' tract participation interest, and the operator of the unitized field sought the approval of Petronas to effect the change in 2017. In 2016, the Company recorded an estimated redetermination expense of $39.1 million ($24.1 million after tax) related to an expected revision in the Company's working interest covering the period from inception through year-end 2016 at Kakap. In February 2017, the Company received Petronas' official approval to the redetermination change that reduced the Company's working interest in oil operations to 6.67% effective at April 1, 2017. Working interest redeterminations are required at different points within the life of the unitized field. Following a partial payment, the remaining redetermination liability of $17.3 million was included as a component of Other current liabilities in the Company's Consolidated Balance Sheet as of June 30, 2018.

Following a further Unitization Framework Agreement (UFA) between the governments of Brunei and Malaysia, the Company now has a 6.37% interest in the Kakap field in Block K Malaysia. The UFA unitized the Gumusut/Kakap (GK) and Geronggong/Jagus East fields effective November 23, 2017. In the fourth quarter 2017, the Company recorded an estimated redetermination expense of $15.0 million ($9.3 million after tax) related to Company's revised working interest. The remaining redetermination liability of $15.0 million was included as a component of Other current liabilities in the Company's Consolidated Balance Sheet as of June 30, 2018.

Note E – Discontinued Operations and Assets Held for Sale

The Company has accounted for its former U.K. and U.S. 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, 2018 and 2017 were as follows:

	Three Months Ended June 30,	Six Months

				Ended June 30,	
(Thousands of dollars)		2018	2017	2018	2017
Revenues	$	6	126	6	256
Income (loss) before income taxes		(398)	(217)	(835)	752
Income tax benefit		–	–	–	–
Income (loss) from discontinued operations	$	(398)	(217)	(835)	752

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, 2018 and December 31, 2017.

(Thousands of dollars)		June 30, 2018	December 31, 2017
Current assets			
Cash	$	14,609	16,631
Accounts receivable		7,058	6,298
Total current assets held for sale	$	21,667	22,929
Current liabilities			
Accounts payable	$	488	837
Refinery decommissioning cost		2,658	2,693
Total current liabilities associated with assets held for sale	$	3,146	3,530

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note F – Financing Arrangements and Debt

At June 30, 2018, the Company had a $1.1 billion senior unsecured guaranteed credit facility (2016 facility) with a major banking consortium, which expires in August 2021. At June 30, 2018, the Company had no outstanding borrowings under the 2016 facility, however, there were $27.9 million of outstanding letters of credit, which reduce the borrowing capacity of the 2016 facility. 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, 2018, the applicable base interest rate would have been 5.5375%. At June 30, 2018, 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 expects to renew the shelf registration in the second half of 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 March 2029. Current maturities of long-term debt and long-term debt on the Consolidated Balance Sheet included $9.7 million and $122.9 million, respectively, associated with this lease at June 30, 2018.

Note G – Other Financial Information

Additional disclosures regarding cash flow activities are provided below.

	Six Months Ended June 30,	
(Thousands of dollars)	2018	2017
Net (increase) decrease in operating working capital other than cash and cash equivalents:		
(Increase) decrease in accounts receivable	$ (15,528)	125,283
Decrease in inventories	16,929	5,918
(Increase) decrease in prepaid expenses	(7,890)	9,206
Increase (decrease) in accounts payable and accrued liabilities	49,311	(136,500)
Increase in income taxes payable	42,618	38,674
Net decrease in noncash operating working capital	$ 85,440	42,581
Supplementary disclosures:		
Cash income taxes paid, net of refunds	$ 36,618	9,448
Interest paid, net of amounts capitalized of $2,377 in 2018 and $2,449 in 2017	79,279	72,136

Non-cash investing activities:		
Asset retirement costs capitalized	$ 1,608	797
Decrease in capital expenditure accrual	39,322	43,370

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note H – 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. 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, 2018 and 2017.

	Three Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2018	2017	2018	2017
Service cost	$ 2,254	2,030	493	424
Interest cost	6,707	6,287	874	967
Expected return on plan assets	(7,453)	(6,475)	–	–
Amortization of prior service cost (credit)	256	254	(9)	(19)
Recognized actuarial loss	5,181	3,509	–	–
Net periodic benefit expense	$ 6,945	5,605	1,358	1,372

	Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2018	2017	2018	2017
Service cost	$ 4,509	4,062	987	849
Interest cost	13,444	13,006	1,748	1,933
Expected return on plan assets	(14,959)	(13,660)	–	–
Amortization of prior service cost (credit)	513	508	(19)	(37)
Recognized actuarial loss	10,396	7,063	–	–
Net periodic benefit expense	$ 13,903	10,979	2,716	2,745

The components of net periodic benefit expense other than the service cost component are included in the line item “Interest and other income (loss)” in Consolidated Statements of Operations.

During the six-month period ended June 30, 2018, the Company made contributions of $13.2 million to its defined benefit pension and postretirement benefit plans. Remaining funding in 2018 for the Company’s defined benefit pension and postretirement plans is anticipated to be $16.5 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note I – Incentive Plans

The costs resulting from all share-based and cash-based incentive plans 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 2017 Annual Incentive Plan (2017 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 2017 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 had a 2013 Stock Plan for Non-Employee Directors (Director Plan) that permitted the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company's Non-Employee Directors. This plan expired in May 2018.

At the Annual Shareholder Meeting held in May 2018, shareholders approved the 2018 Stock Plan for Non-Employee Directors and the 2018 Long-Term Incentive Plan. No further awards will be granted under the 2012 Long-Term Plan.

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

In the first quarter of 2018, the Committee granted 905,500 performance-based RSUs and 736,000 time-based RSUs to certain employees. The fair value of the performance-based RSUs, using a Monte Carlo valuation model, ranged from $28.27 to $30.56 per unit. The fair value of the time-based RSUs was estimated based on the fair market value of the Company's stock on the date of grant. The fair value of the time-based RSUs granted February 6, 2018 was $28.42 per unit, the fair value of the time-based RSUs granted February 20, 2018 was $26.56 per unit, and the fair value of the time-based RSUs granted March 1, 2018 was $25.69 per unit. Additionally, on February 6, 2018 the Committee granted 715,100 cash-settled RSUs (RSUC) to certain employees, and on March 9, 2018 granted 29,000 RSUCs to certain employees. The 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 the RSUCs was equivalent to the equity-settled restricted stock units granted. Also in February, the Committee granted 77,803 shares of time-based RSUs to the Company's Directors under the Non-Employee Director Plan. These units are scheduled to vest on the third anniversary of the date of grant. The estimated fair value of these awards was $28.28 per unit on date of grant.

All stock option exercises are non-cash transactions for the Company. The employee receives net shares, after applicable withholding taxes, upon each stock option exercise. The actual income tax benefit realized from the tax deductions related to stock option exercises of the share-based payment arrangements were immaterial for the six-month period ended June 30, 2018.

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

(Thousands of dollars)	Six Months Ended June 30, 2018	2017
Compensation charged against income before tax benefit	$ 18,970	16,722
Related income tax benefit recognized in income	2,463	5,425

Certain incentive compensation granted to the Company’s named executive officers, to the extent their total compensation exceeds $1.0 million per executive per year, is not eligible for a U.S. income tax deduction under the Tax Cuts and Jobs Act (2017 Tax Act).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note J – Earnings per Share

Net income was used as the numerator in computing both basic and diluted income per Common share for the three-month and six-month periods ended June 30, 2018 and 2017. 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)	2018	2017	2018	2017
Basic method	173,042,626	172,557,978	172,907,537	172,482,223
Dilutive stock options and restricted stock units	939,994	– [1]	2,019,525	534,441
Diluted method	173,982,620	172,557,978	174,927,062	173,016,664

1Due to a net loss in the three-month period ended June 30, 2017, no unvested stock awards were included in the computation of diluted earnings per shares because the effect would have been anti-dilutive.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Antidilutive stock options excluded from diluted shares	3,396,951	5,578,634	3,622,106	4,903,084
Weighted average price of these options	$ 50.22	$ 46.64	$ 50.56	$ 52.01

Note K – Income Taxes

The Company’s effective income tax rate is calculated as the amount of income tax expense (benefit) divided by income from continuing operations before income taxes. For the three-month and six-month periods ended June 30, 2018 and 2017, the Company’s effective income tax rates were as follows:

	2018	2017
Three months ended June 30	44.2%	20.7%

Six months ended June 30	(19.6)%	69.8%

The effective tax rates for most periods where earnings are generated, generally exceed the U.S. statutory tax rate (21% in 2018, 35% in 2017) 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 21% due to similar reasons.

Due to uncertainty related to language in Section 965(n) of the 2017 Tax Act, and specifically whether current operating losses from 2017 were required to be applied to offset a company's deemed taxable repatriation of foreign earnings under the 2017 Tax Act, the Company's provisional tax expense recorded in the Company's December 31, 2017 financial statements reflected use of all the estimated 2017 tax operating loss against the deemed repatriation. This resulted in no loss carryover of 2017 tax operating losses from 2017 into 2018, and foreign tax credits of $228.2 million were fully provided for in the Company's December 31, 2017 financial statements. On April 2, 2018, the Internal Revenue Service issued new guidance related to the Section 965(n) election. This guidance resolved the ambiguity and allowed the Company to preserve the 2017 tax net operating loss as a carryforward by allowing the crediting of the previously unused foreign tax credits against all but $36 million of current income tax on the deemed repatriation of foreign earnings. The preservation of the tax loss carryforward reduced the deferred tax expense for the first quarter of 2018 by $156 million and resulted in a $36 million charge to taxes payable relating to the deemed inclusion. The Company anticipates paying this $36 million tax payable over eight years as permitted by the 2017 Tax Act.

Note K – Income Taxes (Contd.)

The effective tax rate for the three-month period ended June 30, 2018 was above the U.S. statutory tax rate of 21% primarily due to higher tax rates in certain foreign tax jurisdictions combined with expenses in foreign jurisdictions not fully deductible from income at the U.S. statutory rate. 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 related to certain foreign investments, partially offset by income tax expense related to undistributed foreign earnings.

The effective tax rate for the six-month period ended June 30, 2018 was below the U.S. statutory tax rate of 21% primarily due to the discrete tax effect of the new guidance relating to Section 965(n), offset by higher tax rates in certain foreign tax jurisdictions. These impacts were partially offset by higher tax rates in certain foreign tax jurisdictions and expenses in foreign jurisdictions not fully deductible from income at the U.S. statutory tax rate. The effective tax rate for the six-month period ended June 30, 2017 was above the U.S. statutory tax rate due to the Company recording a deferred tax charge of $60.4 million associated with the estimated tax consequence of future repatriation of foreign earnings not considered reinvested into local operations.

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, 2018, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States – 2014; Canada – 2012; Malaysia – 2011; and United Kingdom – 2016.

Note L – 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 reports gains and losses on derivative instruments in the Corporate segment. 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, net in the Consolidated Statements of Operations over the period until the associated notes mature in 2022.

Commodity Price Risks

The Company is subject to commodity price risk related to crude oil it produces and sells. During the first half of 2018 and 2017, 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, 2018, the Company had 21,000 barrels per day in WTI crude oil swap financial contracts maturing ratably during the remainder of 2018 at an average price of $54.88.

At June 30, 2017, the Company had 22,000 barrels per day in WTI crude oil swap financial contracts maturing ratably during 2017.

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, 2018 and 2017.

At June 30, 2018 and December 31, 2017, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

	June 30, 2018		December 31, 2017	
(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 payable	$ (68,882)	Accounts payable	$ (39,093)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

For the three-month and six-month periods ended June 30, 2018 and 2017, the gains and losses recognized in the Consolidated Statements of Operations for derivative instruments not designated as hedging instruments are presented in the following table.

		Gain (Loss)			
		Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of dollars) Type of Derivative Contract	Statement of Operations Location	2018	2017	2018	2017
Commodity	Gain (loss) on crude contracts	$ (37,624)	26,861	(67,126)	63,938
Foreign exchange	Interest and other income (loss)	–	(152)	–	73
		$ (37,624)	26,709	(67,126)	64,011

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, 2018 and 2017, $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 (net of tax) deferred on these matured contracts at June 30, 2018 was $9.1 million, which is recorded, net of income taxes of $2.4 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, net in the Consolidated Statement of Operations during the remaining six months of 2018.

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, 2018 and December 31, 2017 are presented in the following table.

	June 30, 2018	December 31, 2017

(Thousands of dollars)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Liabilities:								
Nonqualified employee savings plans	$ 16,577	–	–	16,577	16,158	–	–	16,158
Commodity derivative contracts	–	68,882	–	68,882	–	39,093	–	39,093
	$ 16,577	68,882	–	85,459	16,158	39,093	–	55,251

The fair value of WTI crude oil derivative contracts in 2018 and 2017 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 Gain (loss) on crude contracts 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, 2018 and December 31, 2017.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note M – Accumulated Other Comprehensive Loss

The components of Accumulated other comprehensive loss on the Consolidated Balance Sheets at December 31, 2017 and June 30, 2018 and the changes during the six-month period ended June 30, 2018 are presented net of taxes in the following table.

(Thousands of dollars)		Foreign Currency Translation Gains (Losses)	Retirement and Postretirement Benefit Plan Adjustments	Deferred Loss on Interest Rate Derivative Hedges	Total
Balance at December 31, 2017	$	(274,830)	(178,987)	(8,426)	(462,243)
2018 components of other comprehensive income (loss):					
Before reclassifications to income and retained earnings		(87,185)	(32,159)	(1,815)	(121,159)
Reclassifications to income		–	7,108 [1]	1,171 [2]	8,279
Net other comprehensive loss		(87,185)	(25,051)	(644)	(112,880)
Balance at June 30, 2018	$	(362,015)	(204,038)	(9,070)	(575,123)

1Reclassifications before taxes of $8,851 are included in the computation of net periodic benefit expense for the six-month period ended June 30, 2018. See Note H for additional information. Related income taxes of $1,743 are included in Income tax expense (benefit) for the six-month period ended June 30, 2018.

2Reclassifications before taxes of $1,482 are included in Interest expense, net, for the six-month period ended June 30, 2018. Related income taxes of $311 are included in Income tax expense (benefit) for the six-month period ended June 30, 2018. See Note L for additional information.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note N – 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 legislation changes, including 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 and may be taken without full consideration of their consequences or may be taken in response to actions of other governments. It is not practical to attempt to predict the likelihood of such actions, the form the actions may take or the effect such actions may have on the Company.

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

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

In early 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 and a further $3.8 million in the first quarter of 2018 associated with the estimated costs of remediating the site. The Company has spent $41.5 million from inception to June 30, 2018. Further refinements in the estimated total cost to remediate the site are anticipated in future periods. 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. As of June 30, 2018, the Company has a remaining accrued liability of $6.3 million associated with this event. In the first quarter of 2018, the Company received $15.0 million in respect to an insurance claim regarding this matter and the outcome of further insurance claims by the Company is pending.

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note O – Commitments

The Company has entered into forward sales contracts to mitigate the price risk for a portion of its 2018 to 2020 natural gas sales volumes in Western Canada. During the period from July 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. These natural gas contracts have been accounted for as normal sales for accounting purposes.

Note P – Business Segments

Information about business segments and geographic operations is reported in the following tables. For geographic purposes, revenues are attributed to the country in which the sale occurs. Corporate, including interest income, other gains and losses (including foreign exchange gains/losses and realized/unrealized gains/losses on crude oil contracts), interest expense and unallocated overhead, is shown in the tables to reconcile the business segments to consolidated totals. Certain reclassifications have been made to 2017 Exploration and production and Corporate External Revenues and Income (Loss) to align with current period presentation.

	Total Assets at June 30,	Three Months Ended June 30, 2018		Three Months Ended June 30, 2017	
(Millions of dollars)	2018	External Revenues	Income (Loss)	External Revenues	Income (Loss)
Exploration and production 1					
United States	$ 4,799.1	318.8	72.6	212.5	(9.6)
Canada	1,745.6	108.4	9.7	88.2	5.2
Malaysia	1,621.7	228.6	83.9	176.5	47.7
Other	160.0	–	(15.0)	–	7.2
Total exploration and production	8,326.4	655.8	151.2	477.2	50.5
Corporate 3	1,597.3	(37.6)	(105.3)	31.1	(67.9)
Assets/revenue/income from continuing operations	9,923.7	618.2	45.9	508.3	(17.4)
Discontinued operations, net of tax	21.7	–	(0.4)	–	(0.2)
Total	$ 9,945.4	618.2	45.5	508.3	(17.6)

	Six Months Ended June 30, 2018		Six Months Ended June 30, 2017	
(Millions of dollars)	External Revenues	Income (Loss)	External Revenues	Income (Loss)

Exploration and production 1				
United States	$ 596.9	108.7	436.7	(10.6)
Canada 2	226.7	34.3	306.1	105.8
Malaysia	439.5	154.3	373.9	106.3
Other	–	(30.5)	–	0.1
Total exploration and production	1,263.1	266.8	1,116.7	201.6
Corporate 3	(59.3)	(52.2)	68.2	(161.5)
Revenue/loss from continuing operations	1,203.8	214.6	1,184.9	40.1
Discontinued operations, net of tax	–	(0.8)	–	0.8
Total	$ 1,203.8	213.8	1,184.9	40.9

1 Additional details about results of oil and gas operations are presented in the tables on pages 1 and 30.

2 Revenue for the six months ended June 30, 2017 includes a pretax gain of $132.4 million related to the sale of Seal heavy oil assets in Canada.

3 In 2018, the Company reported realized and unrealized gains and losses on crude oil contracts in the Corporate segment (previously reported in the Exploration and production business) to reflect how segments are currently evaluated, how resources are allocated and how risk is managed by the Company. The 2017 amounts have been reclassified to reflect comparable disclosure.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS

Overall Review

For the three months ended June 30, 2018, the Company produced 171 thousand barrels of oil equivalent per day. The Company invested $301 million in capital expenditures in the second quarter of 2018 primarily in the United States and Canada. The Company reported net income of $45.5 million for the three months ended June 30, 2018.

For the six months ended June 30, 2018, the Company produced 169 thousand barrels of oil equivalent per day. The Company invested $601 million in capital expenditures in 2018 primarily in the United States and Canada. The Company reported net income of $213.8 million for the six months ended June 30, 2018, which included an income tax gain of $120.0 million as a result of a 2018 Internal Revenue Service (IRS) interpretation of the 2017 Tax Act enacted in the fourth quarter of 2017.

During the three-month and six-month periods ended June 30, 2018, worldwide benchmark oil prices were above average comparable benchmark prices during 2017, while natural gas prices declined versus 2017. Crude oil and condensate volumes were relatively unchanged and natural gas sales volumes were higher principally as a result of growth in Canada and, for the six-month period, the financial results benefited from a one-time U.S. tax gain. In both the quarter and year-to-date periods, the gains from price and volume exchange were partially offset by unrealized losses from crude contracts and higher lease operating expense in the Gulf of Mexico and Canada Onshore businesses. The results are explained in more detail below.

During the second quarter, the Company drilled a successful appraisal well at the Samurai field in the U.S. Gulf of Mexico. Further delineation is expected in the second half of the year.

Results of Operations

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

	Income (Loss) Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of dollars)	2018	2017	2018	2017
Exploration and production	$ 151.2	50.5	266.8	201.6
Corporate and other	(105.3)	(67.9)	(52.2)	(161.5)
Income (loss) from continuing operations	45.9	(17.4)	214.6	40.1
Discontinued operations	(0.4)	(0.2)	(0.8)	0.8
Net income (loss)	$ 45.5	(17.6)	213.8	40.9

Second quarter 2018 vs. 2017

For the second quarter of 2018, Murphy's net income was $45.5 million ($0.26 per diluted share) compared to net loss of $17.6 million ($0.10 per diluted share) in the second quarter of 2017.

The Company's exploration and production (E&P) continuing operations earned $151.2 million in the 2018 quarter compared to earnings of $50.5 million in the 2017 quarter. The E&P results for the 2018 quarter were favorably impacted by higher revenues due to higher realized oil sales prices and higher volumes sold, partially offset by higher lease operating expense.

In 2018 the Company reported realized and unrealized gains and losses on crude oil contracts in the Corporate segment (previously reported in the E&P segment) to reflect how segments are currently evaluated, how resources are allocated and how risk is managed by the Company. The 2017 amounts have been reclassified to the Corporate segment to reflect comparable disclosure.

The Corporate segment had an after-tax net loss of $105.3 million in the second quarter of 2018 compared to an after-tax net loss of $67.9 million in the 2017 period. The unfavorable variance in the current period is primarily due to losses on crude contracts used to hedge price risk, partially off-set by lower unrealized foreign exchange losses. See further details of the Corporate segment results on page 31.

The second quarter of 2018 included losses from discontinued operations of $0.4 million compared to losses of $0.2 million in the second quarter of 2017.

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

Results of Operations (Contd.)

Six Months 2018 vs. 2017

For the first six months of 2018, Murphy's net income was $213.8 million ($1.22 per diluted share) compared to net income of $40.9 million ($0.24 per diluted share) in the first six months of 2017. Income from continuing operations increased from $40.1 million ($0.23 per diluted share) in the first six months of 2017 to $214.6 million ($1.23 per diluted share) in the 2018 period.

The Company's exploration and production (E&P) continuing operations earned $266.8 million in the 2018 period compared to earnings of $201.6 million in the 2017 period. The E&P results for the 2018 period were favorably impacted by higher revenues due to higher realized oil sales prices and higher volumes sold, partially offset by higher lease operating expense. The 2017 results included a pre-tax gain of $132.4 million ($96.0 million after-tax) related to the sale of Seal heavy oil assets.

In 2018 the Company reported realized and unrealized gains and losses on crude oil contracts in the Corporate segment (previously reported in the E&P segment) to reflect how segments are currently evaluated, how resources are allocated and how risk is managed by the Company. The 2017 amounts have been reclassified to the Corporate segment to reflect comparable disclosure.

The Corporate segment had after-tax loss of $52.2 million for the first six months of 2018 compared to an after-tax loss of $161.5 million in the 2017 period with the favorable variance in the current period primarily due to a benefit to income tax expense of $120.0 million related to an IRS interpretation of the 2017 Tax Act. See further details of the Corporate segment results on page 31.

The first six months of 2018 included losses from discontinued operations of $0.8 million ($0.01 per diluted share) compared to income from discontinued operations of $0.8 million ($0.01 per diluted share) in the first six months of 2017.

Exploration and Production

Results of E&P continuing operations are presented by geographic segment below.

Income (Loss)	
Three Months Ended June 30,	Six Months Ended June 30,

(Millions of dollars)	2018	2017	2018	2017
Exploration and production				
United States	$ 72.6	(9.6)	108.7	(10.6)
Canada	9.7	5.2	34.3	105.8
Malaysia	83.9	47.7	154.3	106.3
Other International	(15.0)	7.2	(30.5)	0.1
Total	$ 151.2	50.5	266.8	201.6

Second quarter 2018 vs. 2017

United States E&P operations reported earnings of $72.6 million in the second quarter of 2018 compared to a loss of $9.6 million in the second quarter of 2017. Results were $82.2 million favorable in the 2018 quarter compared to the 2017 period due to higher revenues ($106.3 million) and lower depreciation ($7.2 million), partially offset by higher lease operating expenses ($7.7 million). Higher revenues were primarily due to higher realized prices and higher volumes at the Front Runner and Kodiak assets in the U.S. Gulf of Mexico, while lower depreciation expense was due primarily to lower rates at Eagle Ford Shale and in the U.S. Gulf of Mexico due to 2017 reserve additions. Higher lease operating expenses were principally a result of higher volumes and costs at Front Runner and Kodiak.

Canadian E&P operations reported earnings of $9.7 million in the second quarter 2018 compared to earnings of $5.2 million in the 2017 quarter. Results were favorable $4.5 million compared to the 2017 period due to higher revenue ($20.2 million), partially offset by higher lease operating expense ($3.7 million) and higher depreciation ($10.8 million). Higher revenues were a result of both higher volumes at the Tupper, Kaybob and Placid assets and higher realized crude prices. Higher lease operating expenses and depreciation are a result of higher volumes sold at Tupper, Kaybob and Placid and also at Terra Nova in preparation for a third quarter maintenance operation.

Malaysia E&P operations reported earnings of $83.9 million in the second quarter of 2018 and compared to earnings of $47.7 million in the comparable 2017 period. Results were favorable by $36.2 million due to higher revenues ($52.1 million), partially off-set by higher lease operating expenses ($14.0 million) and higher taxes ($4.0 million). Higher revenues are principally due to higher realized prices. Higher lease operating expenses are due to additional platform and sub-sea maintenance at the Sarawak Asset. Higher taxes are due to the higher pre-tax profits, partially off-set by a tax credit ($11

Results of Operations (Contd.)

Second quarter 2018 vs. 2017(Contd.)

million) for the revaluation of a deferred tax asset from the marginal statutory rate of 25% to the standard statutory rate of 38%.

Other international E&P operations reported a loss from continuing operations of $15.0 million in the second quarter of 2018 compared to a net profit of $7.2 million in the prior year quarter. The loss was $22.2 million higher in the 2018 period versus 2017 due to higher taxes resulting from no repeat of income tax benefits on investments in foreign areas recognized in 2017 ($21.1 million).

Six Months 2018 vs. 2017

United States E&P operations reported earnings of $108.7 million in the first six months of 2018 compared to a net loss of $10.6 million in the first six months of 2017. Results were $119.3 million favorable in the 2018 period compared to the 2017 period due to higher revenues ($160.2 million) and lower depreciation ($23.9 million), partially offset by higher lease operating expenses ($18.3 million), higher exploration expenses ($8.6 million) and higher income taxes ($34.3 million). Higher revenues were primarily due to higher realized prices, while lower depreciation expense was due primarily to lower rates and lower volumes sold at Eagle Ford Shale. Higher lease operating expenses were principally a result of higher costs at Front Runner (due to 2017 Clipper well acquisition) and Kodiak work-over costs in the U.S. Gulf of Mexico business. Higher exploration expenditures are principally a result of data acquisition costs in the U.S Gulf of Mexico business.

Canadian E&P operations reported earnings of $34.3 million in the first six months 2018 compared to earnings of $105.8 million in the 2017 period. Results were unfavorable $71.5 million due to 2017 including a pretax gain of $132.4 million (after tax: $96.0 million) related to the sale of Seal heavy oil assets in Canada in January 2017. Adjusting for the impact of gain on sale of assets, Canadian results of operations improved $24.5 million in the 2018 period compared to the 2017 period due to higher revenue ($53.0 million), insurance proceeds ($11.3 million), partially offset by higher lease operating expense ($11.4 million), higher depreciation ($22.0 million) and higher taxes ($7.5 million). Higher revenues were a result of both higher volumes at the Tupper, Kaybob and Placid assets and higher realized crude prices. Insurance proceeds related to cash received in relation to the spill at the now divested Seal asset. Higher taxes (excluding the Seal gain in 2017) are the result of higher net earnings. Higher lease operating expenses and depreciation are a result of higher volumes sold.

Malaysia E&P operations reported earnings of $154.3 million in the first six months of 2018, compared to earnings of $106.3 million in the comparable 2017 period. Results were favorable by $48.0 million due to higher revenues ($65.6 million), and lower other operating expenses ($7.8 million), partially offset by higher lease operating expenses ($10.1 million), lower exploration expenses ($2.7 million) and higher taxes ($19.5 million). Higher revenues are principally due to higher realized prices. Lower other expenses are due to the cost of a rig exit recorded in 2017. Higher lease operating expenses are due to higher platform and sub-sea maintenance costs. Lower exploration expenses are due to the Marakas-01 well in Block SK314A dry hole expense in 2017.

Other international E&P operations reported a loss from continuing operations of $30.5 million in the first six months of 2018 compared to a profit of $0.1 million in the 2017 period. The loss was $30.6 million higher in the 2018 period versus 2017 primarily related to higher exploration expenses ($5.7 million) in Brazil, Mexico and Vietnam and lower income tax benefits ($33.7 million). Lower income tax benefits are due to no repeat of income tax benefits on investments in foreign areas recognized in 2017.

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

Results of Operations (Contd.)

Exploration and Production

Second quarter 2018 vs. 2017

Total hydrocarbon production averaged 170,993 barrels of oil equivalent per day in the second quarter of 2018, which represented a 5% increase from the 162,857 barrels per day produced in the 2017 quarter.

Average crude oil and condensate production was 90,067 barrels per day in the second quarter of 2018 compared to 89,033 barrels per day in the second quarter of 2017. The increase of 1,034 barrels per day was principally due to higher volumes at Gulf of Mexico as a result of the Clipper acquisition at Front Runner in 2017 and higher volumes in Canada Onshore, partially off-set by lower volumes at Malaysia (4,309 barrels per day) due to field decline. On a worldwide basis, the Company's crude oil and condensate prices averaged $68.03 per barrel in the second quarter 2018 compared to $47.88 per barrel in the 2017 period, an increase of 42% quarter to quarter.

Total production of natural gas liquids (NGL) was 10,120 barrels per day in the 2018 second quarter compared to 9,374 barrels per day in the same 2017 period. The average sales price for U.S. NGL was $26.25 per barrel in the 2018 quarter compared to $17.93 per barrel in 2017. The average sales price for NGL in Canada was $36.66 per barrel in the 2018 quarter compared to $21.16 per barrel in 2017 due in part to the higher value of product produced at the Kaybob and Placid assets.

Natural gas sales volumes averaged 425 million cubic feet per day (MMCFD) in the second quarter 2018 compared to 387 MMCFD in 2017. The increase of 38 MMCFD was a result of increased volumes at Canada (45 MMCFD), partially offset by lower volumes at Malaysia (7 MMCFD). Higher volumes at Canada are a result of more wells online at the Tupper, Kaybob and Placid Onshore businesses. Lower volumes at Malaysia were principally due to field decline. Natural gas prices for the total Company averaged $1.92 per thousand cubic feet (MCF) in the 2018 quarter, versus $2.41 per MCF average in the same quarter of 2017. Natural gas sales prices in the U.S. averaged $2.13 per MCF in the 2018 quarter versus $2.54 per MCF average in the same quarter of 2017. In Canada, natural gas sales prices averaged $1.17 per MCF in the 2018 quarter, versus $1.89 per MCF in the same quarter of 2017. The average realized price for natural gas produced in the 2018 quarter at fields offshore Sarawak was $3.86 per MCF, compared to a price of $3.48 per MCF in the 2017 quarter.

Six Months 2018 vs. 2017

Total hydrocarbon production averaged 169,259 barrels of oil equivalent per day in the first six months of 2018, which represented a 2% increase from the 166,021 barrels per day produced in the 2017 period.

Average crude oil and condensate production was 89,303 barrels per day in the first six months of 2018 compared to 92,300 barrels per day in the first six months of 2017. The decrease of 2,997 barrels per day was principally due to lower volumes at Malaysia (5,148 barrels per day) due to field decline, and lower volumes at Eagle Ford Shale (1,757 barrels per day) due to less new wells brought online. On a worldwide basis, the Company's crude oil and condensate prices averaged $65.85 per barrel in the first six months 2018 compared to $48.89 per barrel in the 2017 period, an increase of 35% period to period.

Total production of natural gas liquids (NGL) was 9,510 barrels per day in the 2018 first six months compared to 9,145 barrels per day in the same 2017 period. The average sales price for U.S. NGL was $20.97 per barrel in the 2018 period compared to $15.32 per barrel in 2017. The average sales price for NGL in Canada was $39.83 per barrel in the 2018 period compared to $20.18 per barrel in 2017. Average NGL prices in Malaysia in the first six months 2018 and 2017 were $70.57 per barrel and $52.40 per barrel, respectively.

Natural gas sales volumes averaged 423 million cubic feet per day (MMCFD) in the first six months 2018 compared to 387 MMCFD in 2017. The increase of 35 MMCFD was a result of increased volumes at Canada (44 MMCFD), partially offset by lower volumes at Malaysia (8 MMCFD) and lower volumes in U.S. (1 MMCFD). Higher volumes at Canada are a result of more wells online at the Tupper, Kaybob & Placid Assets. Lower volumes at Malaysia were principally due to field decline and maintenance activities, while lower volumes in U.S are due to fewer wells brought online at Eagle Ford Shale. Natural gas prices for the total Company averaged $2.04 per thousand cubic feet (MCF) in the 2018 period, versus $2.47 per MCF average in the same period of 2017. Natural gas sales prices in the U.S. averaged $2.29 per MCF in the 2018 period versus $2.43 per MCF average in the same period of 2017. In Canada, natural gas sales prices averaged $1.42 per MCF in the 2018 period, 27% below the $1.97 per MCF average in the same period of 2017.

Additional details about results of oil and gas operations are presented in the tables on pages 29 and 30.

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, 2018 and 2017 follow.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net crude oil and condensate produced – barrels per day	90,067	89,033	89,303	92,300
United States – Eagle Ford Shale	31,936	33,195	31,630	33,397
– Gulf of Mexico	15,365	11,329	14,113	11,844
Canada – Onshore	5,254	3,051	4,809	2,470
– Offshore	7,982	8,199	8,085	9,053
– Heavy1	–	–	–	303
Malaysia – Sarawak	11,354	13,176	12,103	13,346
– Block K	17,596	20,083	17,981	21,887
Brunei	580	–	582	–
Net crude oil and condensate sold – barrels per day	89,995	86,851	88,838	88,361
United States – Eagle Ford Shale	31,936	33,195	31,630	33,397
– Gulf of Mexico	15,365	11,329	14,113	11,844
Canada – Onshore	5,254	3,051	4,809	2,470
– Offshore	7,333	8,938	8,255	8,463
– Heavy 1	–	–	–	303
Malaysia – Sarawak	13,491	13,495	13,407	13,486
– Block K	16,616	16,843	16,624	18,398
Net natural gas liquids produced – barrels per day	10,120	9,374	9,510	9,145
United States – Eagle Ford Shale	6,824	6,921	6,772	6,884
– Gulf of Mexico	1,391	880	1,114	996
Canada – Onshore	1,033	457	959	359

Malaysia – Sarawak	872	1,116	665	906
Net natural gas liquids sold – barrels per day	9,880	8,902	9,643	9,140
United States – Eagle Ford Shale	6,824	6,921	6,772	6,884
– Gulf of Mexico	1,391	880	1,114	996
Canada – Onshore	1,033	457	959	359
Malaysia – Sarawak	632	644	798	901
Net natural gas sold – thousands of cubic feet per day	424,836	386,700	422,673	387,457
United States – Eagle Ford Shale	32,679	34,835	31,894	34,583
– Gulf of Mexico	14,284	11,625	13,548	11,868
Canada – Onshore	264,748	220,171	263,036	218,641
Malaysia – Sarawak	105,199	112,993	105,932	114,767
– Block K	7,926	7,076	8,263	7,598
Total net hydrocarbons produced – equivalent barrels per day 2	170,993	162,857	169,259	166,021
Total net hydrocarbons sold – equivalent barrels per day 2	170,681	160,203	168,927	162,077

1The Company sold the Seal area heavy oil field in January 2017.

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

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Weighted average Exploration and Production sales prices				
Crude oil and condensate – dollars per barrel				
United States 1 – Eagle Ford Shale	$ 68.14	47.42	66.24	48.44
– Gulf of Mexico	68.11	46.65	65.81	47.73
Canada 2 – Onshore	59.45	42.04	57.12	41.43
– Offshore	72.40	47.78	68.69	49.54
Malaysia – Sarawak 3	69.72	48.66	67.13	51.43
– Block K 3	67.20	50.07	65.20	49.42
Natural gas liquids – dollars per barrel				
United States – Eagle Ford Shale	21.29	14.35	20.62	14.99
– Gulf of Mexico	23.27	15.57	23.01	17.69
Canada 2 – Onshore	36.66	21.16	39.83	20.18
Malaysia – Sarawak 3	69.61	57.34	70.57	52.40
Natural gas – dollars per thousand cubic feet				
United States – Eagle Ford Shale	2.11	2.49	2.25	2.38
– Gulf of Mexico	2.18	2.74	2.36	2.62
Canada 2 – Onshore	1.17	1.89	1.42	1.97
Malaysia – Sarawak 3	3.86	3.48	3.62	3.58
– Block K 3	0.25	0.25	0.24	0.24

1 In 2018, the Company reported realized and unrealized gains and losses on crude oil contracts in the Corporate segment (previously in the E&P segment) to reflect how segments are currently evaluated, how resources are allocated and how risk is managed by the Company. The 2017 amounts have been reclassified from the Exploration and Production business to reflect comparable disclosure.

2 U.S. dollar equivalent.

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, 2018 AND 2017

(Millions of dollars)	United States 1	Canada	Malaysia	Other	Total
Three Months Ended June 30, 2018					
Oil and gas sales and other operating revenues	$ 318.8	108.4	228.6	–	655.8
Lease operating expenses	52.0	29.2	55.4	–	136.6
Severance and ad valorem taxes	12.7	0.2	–	–	12.9
Depreciation, depletion and amortization	128.3	56.8	49.8	0.7	235.6
Accretion of asset retirement obligations	4.5	1.9	4.6	–	11.0
Exploration expenses					
Geological and geophysical	0.2	–	0.3	0.7	1.2
Other Exploration	2.4	–	–	5.9	8.3
	2.6	–	0.3	6.6	9.5
Undeveloped lease amortization	8.7	0.2	–	0.7	9.6
Total exploration expenses	11.3	0.2	0.3	7.3	19.1
Selling and general expenses	10.5	6.6	2.0	5.9	25.0
Other	6.9	0.3	(0.1)	1.1	8.2
Results of operations before taxes	92.6	13.2	116.6	(15.0)	207.4
Income tax provisions	20.0	3.5	32.7	–	56.2
Results of operations (excluding corporate overhead and interest)	$ 72.6	9.7	83.9	(15.0)	151.2
Three Months Ended June 30, 2017					
Oil and gas sales and other operating revenues	$ 212.5	88.2	176.5	–	477.2
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 exploration	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	10.1	6.4	3.2	5.0	24.7
Other	10.1	0.6	2.9	–	13.6
Results of operations before taxes	(13.9)	7.3	76.4	(14.2)	55.6
Income tax provisions (benefit)	(4.3)	2.1	28.7	(21.4)	5.1
Results of operations (excluding corporate overhead and interest)	$ (9.6)	5.2	47.7	7.2	50.5

1 In 2018, the Company reported realized and unrealized gains and losses on crude oil contracts in the Corporate segment (previously in the E&P segment) to reflect how segments are currently evaluated, how resources are allocated and how risk is managed by the Company. The 2017 amounts have been reclassified to reflect comparable disclosure.

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

OIL AND GAS OPERATING RESULTS – SIX MONTHS ENDED JUNE 30, 2018 AND 2017

(Millions of dollars)	United States 1	Canada 2	Malaysia	Other	Total
Six Months Ended June 30, 2018					
Oil and gas sales and other operating revenues	$ 596.9	226.7	439.5	–	1,263.1
Lease operating expenses	110.5	59.5	103.1	–	273.1
Severance and ad valorem taxes	24.5	0.5	–	–	25.0
Depreciation, depletion and amortization	249.9	112.5	97.5	1.5	461.4
Accretion of asset retirement obligations	8.9	3.9	8.1	–	20.9
Exploration expenses					
Geological and geophysical	6.2	–	0.5	3.6	10.3
Other exploration	3.6	0.1	–	11.3	15.0
	9.8	0.1	0.5	14.9	25.3
Undeveloped lease amortization	21.4	0.4	–	1.0	22.8
Total exploration expenses	31.2	0.5	0.5	15.9	48.1
Selling and general expenses	24.9	14.3	4.8	11.9	55.9
Other	7.7	(11.4)	(1.3)	1.0	(4.0)
Results of operations before taxes	139.3	46.9	226.8	(30.3)	382.7
Income tax provisions (benefits)	30.6	12.6	72.5	0.2	115.9
Results of operations (excluding corporate overhead and interest)	$ 108.7	34.3	154.3	(30.5)	266.8
Six Months Ended June 30, 2017					
Oil and gas sales and other operating revenues	$ 436.7	306.1	373.9	–	1,116.7
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 exploration	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	25.6	13.6	5.5	9.9	54.6
Other	7.3	0.6	8.0	–	15.9
Results of operations before taxes	(14.3)	147.0	159.3	(33.4)	258.6
Income tax provisions (benefits)	(3.7)	41.2	53.0	(33.5)	57.0
Results of operations (excluding corporate overhead and interest)	$ (10.6)	105.8	106.3	0.1	201.6

1 In 2018, the Company reported realized and unrealized gains and losses on crude oil contracts in the Corporate segment (previously in the E&P segment) to reflect how segments are currently evaluated, how resources are allocated and how risk is managed by the Company. The 2017 amounts have been reclassified to reflect comparable disclosure.

2 Revenue for the six months ended June 30, 2017 includes a pretax gain of $132.4 million related to the sale of Seal heavy oil assets in Canada.

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

Results of Operations (Contd.)

Corporate

Second quarter 2018 vs. 2017

Corporate activities, which include interest income and expense, foreign exchange effects, realized and unrealized gains/losses on crude oil contracts and corporate overhead not allocated to operating functions, reported a net loss of $105.3 million in the 2018 second quarter compared to net loss of $67.9 million in the same 2017 quarter. The $37.4 million variance in the 2018 period was primarily due to losses on crude contracts used to hedge price risk ($37.6 million) vs gains in the prior period ($26.9 million), partially offset by lower foreign exchange losses ($23.0 million). Net interest costs and selling and general expenses were relatively unchanged year over year.

Six Months 2018 vs. 2017

Corporate activities, which include interest income and expense, foreign exchange effects, realized and unrealized gains/losses on crude oil contracts and corporate overhead not allocated to operating functions, reported a net loss of $52.2 million in the 2018 period compared to net loss of $161.5 million in the same 2017 period. The $109.3 million favorable variance in the 2018 period was primarily due to a credit to income tax expense of $120.0 million related to an IRS interpretation of the Tax Cuts and Jobs Act, foreign exchange gains of $2.8 million in 2018 (versus 2017 losses of $54.5 million), partially off-set by losses on crude contracts used to hedge price risk ($67.1 million) vs gains in the prior period ($68.3 million). Further, the 2017 period included a deferred tax charge of $60.4 million associated with the estimated tax consequence of future repatriation of Malaysian and Canadian earnings that were deemed no longer indefinitely invested. Net interest costs and selling and general expenses were relatively unchanged year over year.

Discontinued Operations

The Company has presented its former U.K. and U.S. 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 31, 2018 and 2017 are reflected in the following table.

		Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of dollars)		2018	2017	2018	2017
U.S. refining and marketing	$	(1.3)	–	(1.9)	–
U.K. refining and marketing		0.9	(0.2)	1.1	0.8
Income (loss) from discontinued operations	$	(0.4)	(0.2)	(0.8)	0.8

Financial Condition

Net cash provided by continuing operating activities was $624.5 million for the first six months of 2018 compared to $591.5 million during the same period in 2017. The improvement in cash provided by continuing operations activities in 2018 was primarily attributable to higher revenues from higher prices, off-set by higher cash taxes paid as result of repatriating cash from Canada, current tax payments in Malaysia ($38 million), payments made on hedge (crude contracts to mitigate price risk) losses ($40 million), and higher operating expenses (see more detail on operating results above). Changes in operating working capital from continuing operations increased cash by $85.4 million during the first six months of 2018, compared to $42.2 million in 2017.

Cash used for property additions and dry holes, which includes amounts expensed, were $615.1 million and $431.7 million in the six-month periods ended June 30, 2018 and 2017, respectively. Proceeds from sales of property and equipment generated cash of $0.6 million in 2018 compared to $64.3 million in 2017 primarily relating to proceeds from the sale of the Seal field in Western Canada and the sale of certain non-core assets of Eagle Ford Shale in South Texas in 2017. Total cash dividends to shareholders amounted to $86.5 million for the six months ended June 30, 2018 compared to $86.3 million in the same period of 2017.

Total accrual basis capital expenditures were as follows:

(Millions of dollars)	Six Months Ended June 30, 2018	2017
Capital Expenditures		
Exploration and production	$ 590.9	411.2
Corporate	10.2	3.8
Total capital expenditures	$ 601.1	415.0

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

Financial Condition (Contd.)

The increase in capital expenditures in the exploration and production business in 2018 compared to 2017 was primarily attributable to higher developmental drilling activities in Eagle Ford Shale and Kaybob Duvernay.

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, 2018	2017
Property additions and dry hole costs per cash flow statements	$ 615.1	431.7
Geophysical and other exploration expenses	25.3	26.7
Capital expenditure accrual changes and other	(39.3)	(43.4)
Total capital expenditures	$ 601.1	415.0

Working capital (total current assets less total current liabilities) at June 30, 2018 was $411.8 million, $125.6 million less than December 31, 2017, with the decrease primarily attributable to lower cash and inventory balances offset by higher accounts payable and income tax payable.

At June 30, 2018, long-term debt of $2,897.3 million had decreased by $9.2 million compared to December 31, 2017. A summary of capital employed at June 30, 2018 and December 31, 2017 follows.

	June 30, 2018		December 31, 2017	
(Millions of dollars)	Amount	%	Amount	%
Capital employed				
Long-term debt	$ 2,897.3	38.3 %	$ 2,906.5	38.6 %
Stockholders' equity	4,671.6	61.7 %	4,620.2	61.4 %
Total capital employed	$ 7,569.0	100.0 %	$ 7,526.7	100.0 %

Cash and invested cash are maintained in several operating locations outside the United States. At June 30, 2018, Cash and cash equivalents held outside the U.S. included U.S. dollar equivalents of approximately $698.0 million in Canada and $108.6 million in Malaysia. In addition, $14.6 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, 2018. In certain cases, the Company could incur taxes or other costs should these cash balances be repatriated to the U.S. in future periods. Canada currently collects a 5% withholding tax on any cash repatriated to the U.S.

Accounting and Other Matters

Accounting Principles Adopted

Revenue from Contracts with Customers. In May 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU), which established a comprehensive model of accounting for revenue arising from contracts with customers that superseded most revenue recognition requirements and industry-specific guidance. Under the new standard, the Company recognizes revenue when it transfers control of the commodity to customers in an amount that reflects the consideration the Company expects to be entitled to in exchange for the commodity. Additional disclosures are required to describe the nature, amount, timing and uncertainly of revenue and cash flows from contracts with customers. The Company adopted the new standard in the first quarter of 2018 using the modified retrospective method. The Company performed a review of contracts in each of its revenue streams and implemented accounting policies and internal controls to address the requirements of the ASU. Prior to January 1, 2018, the Company followed the sales method of revenue recognition under Accounting Standards Codification (ASC) Topic 605 and recorded revenue when deliveries occurred and legal ownership of the commodity transferred to the customer.

There was no adjustment to the opening balance of stockholders' equity as at January 1, 2018, resulting from application of the new ASU promulgated in ASC Topic 606 using the modified retrospective method. The comparative information has not been adjusted and continues to be reported under ASC Topic 605 – Revenue Recognition. See also Note C for further discussion of Revenue Recognition.

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

Accounting and Other Matters (Cont.)

Accounting Principles Adopted (Cont.)

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 amendments in this ASU were effective for annual and interim periods beginning after December 15, 2017. The Company adopted this guidance in the first quarter of 2018 and it did not have a material impact on its consolidated financial statements.

Compensation – Retirement Benefits. In March 2017, the FASB issued an ASU 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 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 and interim periods beginning after December 15, 2017. The Company adopted the standard in the first quarter of 2018 and it did not have a material impact on its consolidated financial statements.

Compensation – Stock Compensation. In May 2017, the 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. The Company adopted this accounting standard in the first quarter of 2018 and it did not have material impact on its consolidated financial statements.

Statement of Operations – Reporting Comprehensive Income. In February 2018, the FASB issued an ASU, which allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act. The Company elected to early adopt this accounting standard during the first quarter of 2018 and recorded discrete adjustments from accumulated other comprehensive income to retained earnings of $28.4 million related to retirement and postretirement obligations and $1.8 million related to deferred loss on interest rate derivative hedges. The adoption of this ASU will have no future impact.

Recent Accounting Pronouncements

Leases. In February 2016, the 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 assessing internal processes and analyzing its portfolio of contracts to assess the impact future adoption of this ASU will have on its consolidated financial statements.

Compensation – Stock Compensation. In June 2018, the FASB issued an ASU which supersedes existing guidance for equity-based payments to nonemployees and expands the scope of guidance for stock compensation to include all share-based payment arrangements related to the acquisition of goods and services from both nonemployees and employees. As a result, the same guidance that provides for employee share-based payments, including most of its requirements related to classification and measurement, applies to nonemployee share-based payment arrangements. The ASU 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. The Company anticipates adopting this guidance for the first quarter of 2019 and does not expect it to have a material impact on its consolidated financial statements.

Outlook

Average worldwide crude oil prices in July 2018 have improved from the average prices during the second quarter of 2018. North American natural gas prices are relatively unchanged in July. The Company expects its total oil and natural gas production to average 166,500 – 168,500 barrels of oil equivalent per day in the third quarter 2018. The Company currently anticipates total capital expenditures for the full year 2018 to be approximately $1.18 billion.

The Company will primarily fund its remaining capital program in 2018 using operating cash flow, but will supplement funding where necessary using borrowings under available credit facilities. 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

Outlook (Cont.)

borrowings might be required during the remainder of year to maintain funding of the Company's ongoing development projects.

As of June 30, 2018, the Company has entered into derivative or forward fixed-price delivery contracts to manage risk associated with certain future oil and natural gas sales prices as follows:

Commodities	Contract or Location	Dates	Average Volumes per Day	Average Prices
U.S. Oil	West Texas Intermediate	Jul. – Dec. 2018	21,000 bbls/d	$54.88 per bbl.
Canada Natural Gas	NOVA Gas Transmission Ltd.	Jul. 2018 – Dec. 2020	59 mmcf/d	C$2.81 per mcf

Forward-Looking Statements

This Form 10-Q contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. These statements, which express management's current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of Murphy's exploration programs, the Company's ability to maintain production rates and replace reserves, customer demand for Murphy's products, adverse foreign exchange movements, political and regulatory instability, adverse developments in the U.S. or global capital markets, credit markets or economies generally and uncontrollable natural hazards. For further discussion of risk factors, see Murphy's 2017 Annual Report on Form 10-K on file with the U.S. Securities and

Exchange Commission and page 35 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 L 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, 2018, covering certain future U.S. crude oil sales volumes in 2018. A 10% increase in the respective benchmark price of these commodities would have increased the recorded net payable associated with these derivative contracts by approximately $27.3 million, while a 10% decrease would have decreased the recorded net payable by a similar amount.

There were no derivative foreign exchange contracts in place at June 30, 2018.

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, 2018, there were no 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 2017 Form 10-K filed on February 26, 2018. The Company has not identified any additional risk factors not previously disclosed in its 2017 Form 10-K report.

ITEM 6. EXHIBITS

The Exhibit Index on page 37 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 8, 2018

(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.