UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2019

OR

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

For the transition period from to

Commission file number 1-8590

MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

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

(870) 862-6411

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock, $1.00 Par Value	MUR	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter (as of June 30, 2019) – $2,748,431,387.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2020 was 153,169,317.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 13, 2020 have been incorporated by reference in Part III herein.

MURPHY OIL CORPORATION
2019 FORM 10-K
TABLE OF CONTENTS

PART I

Item 1. BUSINESS

Summary

Murphy Oil Corporation is a global oil and natural gas exploration and production company. As used in this report, the terms Murphy, Murphy Oil, we, our, its and Company may refer to Murphy Oil Corporation or any one or more of its consolidated subsidiaries.

The Company was originally incorporated in Louisiana in 1950 as Murphy Corporation. It was reincorporated in Delaware in 1964, at which time it adopted the name Murphy Oil Corporation, and was reorganized in 1983 to operate primarily as a holding company of its various businesses. In 2013, the U.S. downstream business was separated from Murphy Oil Corporation's oil and natural gas exploration and production business. For reporting purposes, Murphy's exploration and production activities are subdivided into three geographic segments, including the United States, Canada, and all other countries. Additionally, Corporate activities include interest income, interest expense, foreign exchange effects, corporate risk management activities and administrative costs not allocated to the segments. The Company's corporate headquarters are located in El Dorado, Arkansas.

At December 31, 2019, Murphy had 822 employees (2018: 1,108).

In addition to the following information about each business activity, data about Murphy's operations, properties and business segments, including revenues by class of products and financial information by geographic area, are provided on pages 22 through 36, 68 through 70, 94 through 108 and 111 of this Form 10-K report.

Interested parties may obtain the Company's public disclosures filed with the Securities and Exchange Commission (SEC), including Form 10-K, Form 10-Q, Form 8-K and other documents, by accessing the Investor Relations section of Murphy Oil Corporation's Website at www.murphyoilcorp.com.

Exploration and Production

The Company explores for and produces crude oil, natural gas and natural gas liquids worldwide. The Company's management team directs the Company's worldwide exploration and production activities. The business maintains upstream operating offices, with the most significant of these including Houston, Texas and Calgary, Alberta.

In July 2019, the Company closed a divestiture of its two subsidiaries conducting Malaysian operations, Murphy Sabah Oil Co., Ltd. and Murphy Sarawak Oil Co., Ltd., in a transaction with PTT Exploration and Production Public Company Limited (PTTEP). Total cash consideration received upon closing was $2.0 billion. Effective January 1, 2019, Malaysia operations were reported as discontinued operations, and a gain on sale of $985.4 million was recorded as part of discontinued operations on the Consolidated Statement of Operations. Murphy is entitled to receive a $100.0 million bonus payment contingent upon certain future exploratory drilling results prior to October 2020.

During 2019, Murphy's principal continuing exploration and production activities were conducted in the United States by wholly-owned Murphy Exploration & Production Company – USA (Murphy Expro USA) and its subsidiaries, in Canada by wholly-owned Murphy Oil Company Ltd. (MOCL) and its subsidiaries, and in Australia, Brazil, Brunei, Mexico and Vietnam by wholly-owned Murphy Exploration & Production Company – International (Murphy Expro International) and its subsidiaries. Murphy's continuing operations hydrocarbon production in 2019 was in the United States, Canada and Brunei (held for sale).

Unless otherwise indicated, all references to the Company's offshore U.S. and total oil, natural gas liquids and natural gas production and sales volumes, and proved reserves include a noncontrolling interest in MP Gulf of Mexico, LLC (MP GOM; see further details below).

Murphy's worldwide 2019 production (excluding Malaysia) on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 185,649 barrels of oil equivalent per day, an increase of 49.3% compared to 2018.

See Management's Discussion and Analysis section for further details on 2019 production and sales volume.

<u>United States</u>

In the United States, Murphy has production of crude oil, natural gas liquids and natural gas primarily from fields in the Gulf of Mexico and in the Eagle Ford Shale area of South Texas. The Company produced approximately 112,000 barrels of crude oil and natural gas liquids per day and approximately 83 MMCF of natural gas per day in the U.S. in 2019. These amounts represented 78.9% of the Company's total worldwide oil and natural gas liquids and 23.4% of worldwide natural gas production volumes.

Offshore

On May 31, 2019, the Company completed a transaction with LLOG Exploration Offshore L.L.C. and LLOG Bluewater Holdings, L.L.C., (LLOG), which was effective January 1, 2019. Through this transaction, Murphy acquired strategic deepwater Gulf of Mexico assets which added approximately 67.4 MMBOE of proven reserves at May 31, 2019.

Under the terms of the transaction, Murphy paid cash consideration of $1,238.4 million. Murphy has a future obligation to pay $50 million following first oil from certain development projects, as well as, additional contingent consideration of up to $200 million in the event that certain revenue thresholds are exceeded between 2019 and 2022.

In 2018, Murphy Expro USA and Petrobras America Inc. (PAI), a subsidiary of Petróleo Brasileiro S.A., closed a transaction among Murphy, PAI and MP Gulf of Mexico, LLC (MP GOM), a subsidiary of Murphy. The transaction had an effective date of October 1, 2018. MP GOM is now owned 80% by Murphy and 20% by PAI. Throughout this 10-K report, unless stated otherwise, financial and operational metrics relating to MP GOM include PAI's 20% noncontrolling interest in MP GOM. 100% of revenues, costs, assets, liabilities and cash flows of MP GOM are fully consolidated in the financial statements.

During 2019, approximately 64% of total U.S. hydrocarbon production was produced at fields in the Gulf of Mexico. Approximately 79% of Gulf of Mexico production in 2019 was derived from six fields, including Dalmatian, Kodiak, Marmarlard, Neidermeyer, St. Malo and Cascade/Chinook. Total average daily production in the Gulf of Mexico in 2019 was 71,700 barrels of liquids and approximately 14 MMCF of natural gas. At December 31, 2019, Murphy had total proved reserves for Gulf of Mexico fields of 187.5 million barrels of oil and natural gas liquids and 132.9 billion cubic feet of natural gas.

Below is a summary of Company's major working interests in the U.S. Gulf of Mexico:

Field	Working Interest (incl. NCI)	Blocks
Operated:		
Calliope	28.5%	Mississippi Canyon 565/609
Cascade	100.0%	Walker Ridge 206/250
Chinook	100.0%	Walker Ridge 425/469
Cottonwood	100.0%	Garden Banks 244
Dalmatian	70.0%	DeSoto Canyon Blocks 4 and 134
Front Runner	62.5%	Green Canyon Blocks 338/339
Hoffe Park	60.0%	Mississippi Canyon 122/165/166
Khaleesi	34.0%	Green Canyon 345/389/390/434
King Cake	31.5%	Atwater Valley 23
Marmalard	25.6%	Mississippi Canyon 255/299/300
Marmalard East	67.1%	Mississippi Canyon 301
Medusa	60.0%	Mississippi Canyon Blocks 538/582
Mormont	34.0%	Green Canyon 478
Nearly Headless Nick	26.84%	Mississippi Canyon 387
Neidermeyer	52.8%	Mississippi Canyon 208/209/252
Otis	70.0%	Mississippi Canyon 79
Ourse	31.25%	Mississippi Canyon 895
Powerball	75.0%	South Timbalier South 231/232
Samurai	50.0%	Green Canyon 432
Son of Bluto II	26.84%	Mississippi Canyon 386/431
Thunder Hawk	62.5%	Mississippi Canyon Block 734

Field	Working Interest (incl. NCI)	Blocks
Non-operated:		
Habanero	33.75%	Garden Banks 341
Kodiak	54.1%	Mississippi Canyon Blocks 727/771
Lucius	11.5%	Keathley Canyon 874/875/918/919
Northwestern	25.0%	Garden Banks 200/201
SMI 280	50.0%	South Marsh Island 280
St. Malo	25.0%	Walker Ridge 633/634/677/678
Tahoe	30.0%	Viosca Knoll 783

Onshore

The Company holds rights to approximately 135 thousand gross acres in South Texas in the Eagle Ford Shale unconventional oil and natural gas play. Total 2019 production in the Eagle Ford Shale area was 40,204 barrels of oil and liquids per day and approximately 32 MMCF per day of natural gas. On a barrel of oil equivalent basis, Eagle Ford Shale production accounted for 36.0% of total U.S. production volumes in 2019. At December 31, 2019, the Company's proved reserves for the U.S. Onshore business totaled 243.1 million barrels of liquids and 283.9 billion cubic feet of natural gas.

Canada

In Canada, the Company holds one wholly-owned natural gas area (Tupper Montney), working interests in the Kaybob Duvernay (operated), liquids rich Placid Montney (non-operated) lands, and two non-operated assets – the Hibernia and Terra Nova fields offshore Newfoundland in the Jeanne d'Arc Basin.

Onshore

The Company has approximately 94 thousand gross acres of Tupper Montney mineral rights located in northeast British Columbia. In 2016, the Company completed its transaction to divest natural gas processing and sales pipeline assets that support Murphy's Montney natural gas fields in the Tupper area. Connected with this sale, the Company entered into a commitment for 285 MMCFD of natural gas processing capacity for minimum monthly payments through 2035. In 2018, the Company entered into a further commitment, commencing November 2020 for an additional 200 MMCFD processing capacity.

In 2016, the Company acquired a 70% operated working interest in Kaybob Duvernay lands and a 30% non-operated working interest in liquids rich Placid Montney lands, both in Alberta. The acquisition included an additional $168.0 million in the form of a carried interest on the Kaybob Duvernay property. As of December 31, 2019, $152.7 million of the carried interest had been paid and the remainder is expected to be paid in the first quarter of 2020. The Company has approximately 348 thousand gross acres of Kaybob Duvernay and Placid Montney mineral rights.

Also in 2016, the Company entered into an agreement to sell its wholly-owned Seal field located in the Peace River area of northwest Alberta. This sale was completed in January 2017. Finally, in 2016, MOCL completed the sale of its 5% undivided interest in Syncrude Canada Ltd. (Syncrude).

Daily production in 2019 in onshore Canada averaged 7,600 barrels of liquids and approximately 271 MMCF of natural gas, an increase of 12.0% and 1.8% versus 2018, respectively. Total onshore Canada proved liquids and natural gas reserves at December 31, 2019, were approximately 29.3 million barrels and 1.6 trillion cubic feet, respectively.

Offshore

Murphy has a 6.5% working interest in Hibernia Main, a 4.3% working interest in Hibernia South Extension, and a 10.475% working interest at Terra Nova. Oil production in 2019 was approximately 6,543 barrels of oil per day for the two offshore Canada fields. Total proved oil reserves at December 31, 2019 for the two fields were approximately 19.3 million barrels of liquids and 12.4 billion cubic feet of natural gas.

Brunei

The Company has a working interest of 8.05% in Block CA-1 and a 30% working interest in Block CA-2; both assets are currently held for sale.

On November 23, 2017, the governments of both Brunei and Malaysia signed a Unitization Framework Agreement (UFA) which resulted in the Jagus East discovery in Block CA-1 forming part of a unitized field with the Gumusut-Kakap (GK) Unit in Malaysia.

Following the UFA, on July 4, 2018, a Participation Agreement was signed which finalized the Company's interest in the Brunei section of the GK Unit.

The CA-1 and CA-2 blocks cover 1.44 million and 1.49 million gross acres, respectively. Four exploration wells were drilled in Block CA-1 and seven exploration wells were drilled in Block CA-2 at the end of 2019.

The Company has a 30% non-operating working interest in Block CA-2. In December 2014, the governmental authority, PetroleumBrunei, approved an eight-year natural gas holding period until December 2022. The consortium is presently carrying out pre-development engineering related to the planned Kelidang Cluster development with the aim to achieve project sanction in 2021.

Australia

In Australia, the Company holds four offshore exploration permits and serves as operator of three of them. All of the permits have high quality 3D seismic data available and exploration studies are ongoing. None of the permits has a drilling commitment and all have options to renew beyond the current expiry dates.

Vietnam

The Company holds a 65% working interest in Blocks 144 and 145; and a 40% interest in Block 15-1/05 and Block 15-2/17. The Company is operator of each of the three blocks.

In November 2019, the Company signed a new PSC with Vietnam National Oil and Gas Group, PetroVietnam Exploration Production Corporation Ltd. (PVEP) and SK Innovation Company Ltd., resulting in the Company now holding a 40% interest in Block 15-2/17.

In August 2015, the Company signed a farm-in agreement to acquire 35% of Block 15-1/05 and in March 2018 became the operator and increased its working interest to 40%. Block 15-1/05 contains the Lac Da Vang (LDV) discovered field and the consortium is progressing pre-development engineering. Declaration of Commerciality was made in January 2019, the field Outline Development Plan was approved in August 2019, and the Exploration Phase expired in December 2019. The Lac Da Trang (LDT) 1X exploration well, the last remaining commitment of the PSC, was completed in April 2019. First oil from LDV is currently planned by the end of 2022.

In November 2012, the Company signed a PSC with Vietnam National Oil and Gas Group and PVEP, where it holds a 65% interest and operatorship of Blocks 144 and 145. The blocks cover approximately 6.56 million gross acres and are located in the outer Phu Khanh Basin. The Company acquired 2D seismic for these blocks in 2013 and undertook seabed surveys in 2015 and 2016. The remaining commitment for the acquisition, processing and interpretation of six hundred square kilometers (600 km2) of 3D seismic is tentatively scheduled for 2021.

Mexico

In 2016, Murphy and joint venture partners were the successful bidders on Block 5, which was offered as part of Mexico's fourth phase, round one deepwater auction. Murphy was formally awarded the block in March 2017. Murphy is the operator of the Block with a 40% working interest. Block 5 is located in the deepwater Salinas Basin covering approximately 640,000 gross acres (2,600 square kilometers), with water depths ranging from 2,300 to 3,500 feet (700 to 1,100 meters). The initial exploration period for the license is four years and includes a commitment to drill one exploration well which was drilled in 2019.

Brazil

The Company now holds an interest in 6 blocks in the offshore regions of the Sergipe-Alagoas Basin (SEAL) in Brazil (SEAL-M-351, SEAL-M-428, SEAL-M-430, SEAL-M-501, SEAL-M-503 and SEAL-M-573). ExxonMobil is the operator of the blocks. Murphy has a 20% working interest, ExxonMobil has a 50% working interest and Enauta holds a 30% working interest. Murphy and the same partners were successful bidders for three more blocks (SEAL-M-505, 575, 637) in September 2019, award of these blocks was pending government approval at year-end 2019 and were approved in February 2020.

Subject to government approval, Murphy has also farmed into 3 additional blocks in the Portiguar Basin (POT-M-857, POT-M-863, and POT-M-865) with a 30% working interest; Wintershall Dea is the operator.

Murphy's total acreage position in Brazil as of December 31, 2019 (excluding 6 blocks pending approval at 2019 year end) is approximately 1,119,555 gross acres, offsetting several major Petrobras discoveries. There are no well commitments.

Proved Reserves

Total proved reserves for crude oil, natural gas liquids and natural gas as of December 31, 2019 are presented in the following table.

	Proved Reserves			
	All Products	Crude Oil	Natural Gas Liquids	Natural Gas
Proved Developed Reserves:	(MMBOE)	(MMBBL)		(BCF)
United States	**273.4**	**205.0**	**26.2**	**253.1**
Onshore	137.7	90.2	19.0	171.1
Offshore [1]	135.7	114.8	7.2	82.0
Canada	**198.1**	**25.1**	**1.9**	**1,026.7**
Onshore	179.4	8.4	1.9	1,014.7
Offshore	18.7	16.7	—	12.0
Other [2]	**0.8**	**0.8**	**—**	**—**
Total proved developed reserves	**472.3**	**230.9**	**28.1**	**1,279.8**
Proved Undeveloped Reserves:				
United States	**226.7**	**172.8**	**26.6**	**163.7**
Onshore	152.7	111.3	22.6	112.8
Offshore [3]	74.0	61.5	4.0	50.9
Canada	**126.0**	**20.2**	**1.4**	**626.2**
Onshore	123.4	17.7	1.4	625.8
Offshore	2.6	2.5	—	0.4
Total proved undeveloped reserves	**352.7**	**193.0**	**28.0**	**789.9**
Total proved reserves [4]	**825.0**	**423.9**	**56.1**	**2,069.7**

[1] Includes proved developed reserves of 19.6 MMBOE, consisting of 17.7 MMBBL oil, 0.7 MMBBL NGLs, and 7.1 BCF natural gas, attributable to the noncontrolling interest in MP GOM.

[2] Proved developed reserves attributed to asset held for sale in Brunei.

[3] Includes proved undeveloped reserves of 5.0 MMBOE, consisting of 4.4 MMBBL oil, 0.2 MMBBL NGLs, and 2.4 BCF natural gas, attributable to the noncontrolling interest in MP GOM.

[4] Includes proved reserves of 24.6 MMBOE, consisting of 22.1 MMBBL oil, 0.9 MMBBL NGLs, and 9.5 BCF natural gas, attributable to the noncontrolling interest in MP GOM.

Proved Reserves (Contd.)

Murphy Oil's 2019 total proved reserves and proved undeveloped reserves are reconciled from 2018 as presented in the table below:

(Millions of oil equivalent barrels) [1]	Total Proved Reserves	Total Proved Undeveloped Reserves
Beginning of year	844.0	413.7
Revisions of previous estimates	28.4	(42.6)
Extensions and discoveries	73.3	63.0
Conversions to proved developed reserves [2]	—	(47.4)
Purchases of properties	76.2	36.5
Sale of properties	(121.5)	(70.5)
Production	(75.4)	—
End of year [3]	**825.0**	**352.7**

[1] For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of oil using a ratio of six MCF of natural gas to one barrel of oil.
[2] Includes 1.5 MMBOE of total proved undeveloped reserves attributable to conversion of certain LLOG properties acquired in 2019.
[3] Includes 24.6 MMBOE and 5.0 MMBOE for total proved and proved undeveloped reserves, respectively, attributable to the noncontrolling interest in MP GOM.

During 2019, Murphy's total proved reserves decreased by 19.0 million barrels of oil equivalent (MMBOE). The decrease in reserves principally relates to the Malaysia divestiture of 121.4 MMBOE and 2019 production of 75.4 MMBOE; partially offset by Gulf of Mexico acquisitions of 76.2 MMBOE and extensions and discoveries of 38.5 MMBOE in the Eagle Ford Shale, 23.6 MMBOE in the U.S. Gulf of Mexico, and 11.1 MMBOE in Canada.

Murphy's total proved undeveloped reserves at December 31, 2019 decreased 61.0 MMBOE from a year earlier. The proved undeveloped reserves reported in the table as extensions and discoveries during 2019 were predominantly attributable to three areas: the Eagle Ford Shale in South Texas, the U.S. Gulf of Mexico, and the onshore Canada area of Kaybob Duvernay. Each of these areas had active development work ongoing during the year. The majority of proved undeveloped reserves associated with revisions of previous estimates was the result of deferral of capital expenditures in onshore Canada. The majority of the proved undeveloped reserves migration to the proved developed category are attributable to drilling in the Eagle Ford Shale, Gulf of Mexico, Kaybob Duvernay, and Tupper Montney.

The Company spent approximately $918 million in 2019 to convert proved undeveloped reserves to proved developed reserves. The Company expects to spend approximately $1,370 million in 2020, $1,150 million in 2021 and $810 million in 2022 to move currently undeveloped proved reserves to the developed category. The anticipated level of spending in 2020 primarily includes drilling and development in the Eagle Ford Shale, Kaybob Duvernay, Tupper Montney, and Gulf of Mexico areas.

At December 31, 2019, proved reserves are included for several development projects, including oil developments at the Eagle Ford Shale in South Texas; Kaybob Duvernay in onshore Canada; deepwater Gulf of Mexico; and natural gas developments in Tupper Montney. Total proved undeveloped reserves associated with various development projects at December 31, 2019 were approximately 352.7 MMBOE, which represent 43% of the Company's total proved reserves.

Certain development projects have proved undeveloped reserves that will take more than five years to bring to production. The Company operates deepwater fields in the Gulf of Mexico that have twenty undeveloped locations that exceed this five-year window. Total reserves associated with the twenty locations amount to approximately 2.6% of the Company's total proved reserves at year-end 2019. The development of certain of these reserves stretches beyond five years due to limited well slots available, thus making it necessary to wait for depletion of other wells prior to initiating further development of these locations.

Murphy Oil's Reserves Processes and Policies

As per the SEC, proved oil and natural gas reserves are "those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The SEC has defined reasonable certainty for proved reserves, as a "high degree of confidence that the quantities will be recovered." Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, could be more or less than the estimated amounts.

Murphy has established both internal and external controls for estimating proved reserves that follow the guidelines set forth by the SEC for oil and natural gas reporting. Certain qualified technical personnel of Murphy from the various exploration and production offices are responsible for the preparation of proved reserve estimates and these technical representatives provide the necessary information and maintain the data as well as the documentation for all properties.

The Murphy proved reserves are then consolidated and reported through the Corporate Reserves group. Murphy's General Manager of Corporate Reserves (Reserves Manager) leads the Corporate Reserves group that also includes Corporate reserve engineers and support staff in which all are independent of the Company's oil and natural gas operational management and technical personnel. The Reserves Manager joined Murphy in 2018 and has more than 19 years of industry experience. He has a Bachelor of Science and a Master of Science degree in Petroleum Engineering as well as a Master of Business Administration. The Reserves Manager is also a licensed Professional Engineer in the State of Texas. The Reserves Manager reports to the Chief Financial Officer and makes annual presentations to the Board of Directors about the Company's reserves. The Reserves Manager and the Corporate reserve engineers review and discuss reserves estimates directly with the Company's technical staff in order to make every effort to ensure compliance with the rules and regulations of the SEC. The Reserves Manager coordinates and oversees the third-party audits which are performed annually and under Company policy generally target coverage of at least one-third of the barrel oil-equivalent volume of the Company's proved reserves.

The estimated proved reserves reported in this Form 10-K are prepared by Murphy's internal employees. Internal audits may also be performed by the Reserves Manager and qualified engineering staff from areas of the Company other than the area being audited by third parties. In 2019, 99% of the Proved reserves were audited by third-party auditors. Murphy engaged both Ryder Scott Company, L.P. (Ryder Scott) and McDaniel & Associates Consultants Ltd. (McDaniel) to perform a reserves audit of 60.6% and 38.7% of the Company's total proved reserves, respectively.

Each significant exploration and production office also maintains one or more Qualified Reserve Estimators (QRE) on staff. The QRE is responsible for estimating and evaluating reserves and other reserves information for his or her assigned area. The QRE may personally make the estimates and evaluations of reserves or may supervise and approve the estimation and evaluation thereof by others. A QRE is professionally qualified to perform these reserves estimates as a result of having sufficient educational background, professional training, and professional experience to enable him or her to exercise prudent professional judgment. Larger offices (Houston and Calgary) of the Company also employ a Regional Reserves Coordinator (RRC) who supervises the local QREs. The RRC is usually a senior QRE who has the primary responsibility for coordinating and submitting reserves information to senior management.

QRE qualification requires a minimum of five years of practical experience in petroleum engineering or petroleum production geology, with at least three years of such experience being in the estimation and evaluation of reserves, and either a bachelors or advanced degree in petroleum engineering, geology or other discipline of engineering or physical science from a college or university of recognized stature, or the equivalent thereof from an appropriate government authority or professional organization. Murphy provides annual training to all company reserves estimators to ensure SEC requirements associated with reserves estimation and Form 10-K reporting are fulfilled. The training includes materials provided to each participant that outlines the latest guidance from the SEC as well as best practices for many engineering and geologic matters related to reserves estimation.

The Company's QREs maintain files containing pertinent data regarding each significant reservoir. Each file includes sufficient data to support the calculations or analogies used to develop the values. Examples of data included in the file, as appropriate, include: production histories; pertinent drilling and workover histories; bottom hole pressure data; volumetric, material balance, analogy, or other pertinent reserve estimation data; production performance curves; narrative descriptions of the methods and logic used to determine reserves values; maps and logs; and a signed copy of the documentation stating that, in their opinion, the reserves have been calculated, reviewed, documented, and reported in compliance with SEC regulations. When reserves calculations are completed by technical personnel with the support of the QREs and appropriately reviewed by RRCs, the Corporate reserves engineers and the Reserves Manager, the conclusions are reviewed and approved with the heads of the Company's exploration and production business units and other senior management on an annual

Murphy Oil's Reserves Processes and Policies (Contd).

basis. The Company's Controller's department is responsible for preparing and filing reserves schedules within the Form 10-K report.

To ensure accuracy and security of reported reserves, the proved reserves estimates are coordinated in industry-standard software with access controls for approved users. In addition, Murphy complies with audit controls concerning the various business processes related to reserves.

More information regarding Murphy's estimated quantities of proved reserves of crude oil, natural gas liquids, and natural gas for the last three years are presented by geographic area on pages 95 through 102 of this Form 10-K report. Also, Murphy currently has no oil and natural gas reserves from non-traditional sources. Murphy has not filed and is not required to file any estimates of its total proved oil or natural gas reserves on a recurring basis with any federal or foreign governmental regulatory authority or agency other than the U.S. Securities and Exchange Commission. Annually, Murphy reports gross reserves of properties operated in the United States to the U.S. Department of Energy; such reserves are derived from the same data from which estimated proved reserves of such properties are determined.

Crude oil, condensate and natural gas liquids production and sales, and natural gas sales by geographic area with weighted average sales prices for each of the three years ended December 31, 2019 are shown on pages 28 through 29 and 31 of this Form 10-K report.

Production expenses for the last three years in U.S. dollars per equivalent barrel are discussed beginning on page 32 of this Form 10-K report.

Supplemental disclosures relating to oil and natural gas producing activities are reported on pages 94 through 109 of this Form 10-K report.

At December 31, 2019, Murphy held leases, concessions, contracts or permits on developed and undeveloped acreage as shown by geographic area in the following table. Gross acres are those in which all or part of the working interest is owned by Murphy. Net acres are the portions of the gross acres attributable to Murphy's interest.

	Developed		Undeveloped		Total	
Area (Thousands of acres)	Gross	Net	Gross	Net	Gross	Net
United States – Onshore	109	97	38	35	147	132
– Gulf of Mexico	40	18	658	334	698	352
Total United States	149	115	696	369	845	484
Canada – Onshore	116	91	404	287	520	378
– Offshore	101	8	28	1	129	9
Total Canada	217	99	432	288	649	387
Mexico	—	—	636	254	636	254
Brazil	—	—	1,120	224	1,120	224
Australia	—	—	5,100	2,571	5,100	2,571
Brunei	—	—	2,935	562	2,935	562
Vietnam	—	—	7,324	4,571	7,324	4,571
Spain	—	—	8	1	8	1
Totals	366	214	18,251	8,840	18,617	9,054

Certain acreage held by the Company will expire in the next three years.

Scheduled expirations in 2020 include 447 thousand net acres in Brunei, 117 thousand net acres in onshore Canada; 9 thousand net acres in onshore United States; and 5 thousand net acres in the Gulf of Mexico.

Acreage currently scheduled to expire in 2021 include 41 thousand net acres in onshore Canada; and 7 thousand acres in the Gulf of Mexico.

Scheduled expirations in 2022 include 75 thousand net acres in Brazil; 65 thousand acres in the Gulf of Mexico; and 8 thousand net acres in onshore Canada.

As used in the three tables that follow, "gross" wells are the total wells in which all or part of the working interest is owned by Murphy, and "net" wells are the total of the Company's fractional working interests in gross wells expressed as the equivalent number of wholly-owned wells. An “exploratory” well is drilled to find and produce crude oil or natural gas in an unproved area and includes delineation wells which target a new reservoir in a field known to be productive or to extend a known reservoir beyond the proved area. A “development” well is drilled within the proved area of an oil or natural gas reservoir that is known to be productive.

The following table shows the number of oil and natural gas wells producing or capable of producing at December 31, 2019.

	Oil Wells		Natural Gas Wells	
	Gross	Net	Gross	Net
Country				
United States	1,085	890	25	14
Canada	45	32	435	339
Totals	1,130	922	460	353

Murphy’s net wells drilled in the last three years are shown in the following table.

	United States		Canada		Other		Totals	
	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry
2019								
Exploration	**0.6**	**—**	**—**	**—**	**—**	**—**	**0.6**	**—**
Development	**84.6**	**—**	**18.6**	**—**	**—**	**—**	**103.2**	**—**
2018								
Exploration	0.5	0.4	—	—	—	—	0.5	0.4
Development	46.6	—	28.1	—	—	—	74.7	—
2017								
Exploration	—	—	—	—	—	—	—	—
Development	68.7	—	27.2	—	—	—	95.9	—

Murphy’s drilling wells in progress at December 31, 2019 are shown in the following table. The year-end well count includes wells awaiting various completion operations. Of the U.S. net wells included below, one is located in the U.S. Gulf of Mexico and the others are located in the Eagle Ford Shale area of South Texas. Canada net wells included below are located in the Kaybob Duvernay area of Western Canada.

	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Country						
United States	—	—	19.0	17.1	19.0	17.1
Canada	—	—	4.0	2.8	4.0	2.8
Totals	—	—	23.0	19.9	23.0	19.9

Discontinued Operations

Malaysia – In July 2019, the Company closed a divestiture of its two subsidiaries conducting Malaysian operations, Murphy Sabah Oil Co., Ltd. and Murphy Sarawak Oil Co., Ltd., in a transaction with PTT Exploration and Production Public Company Limited (PTTEP) which was effective January 1, 2019. Total cash consideration received upon closing was $2.0 billion. A gain on sale of $985.4 million was recorded as part of discontinued operations on the Consolidated Statement of Operations. The Company has accounted for and reported the Malaysia business as discontinued operations for all periods presented.

Refining and Marketing – The Company decommissioned the Milford Haven refinery units and completed the sale of its remaining downstream assets in the U.K. in 2015 for cash proceeds of $5.5 million. The Company has accounted for and reported this U.K. downstream business as discontinued operations for all periods presented. In October 2019, the current owner of the former Milford Haven Refinery issued a completion certificate acknowledging the Company had satisfactorily completed all obligations regarding the decommissioning and demolition of the facility’s refinery equipment.

Environmental

Murphy’s businesses are subject to various international, national, state, provincial and local environmental laws and regulations that govern the manner in which the Company conducts its operations. The Company anticipates that these requirements will continue to become more complex and stringent in the future.

Further information on environmental matters and their impact on Murphy are contained in Management’s Discussion and Analysis of Financial Condition and Results of Operations on pages 36 and 37.

Website Access to SEC Reports

Murphy Oil’s internet Website address is http://www.murphyoilcorp.com. The information contained on the Company’s Website is not part of this report on Form 10-K.

The Company’s Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on Murphy’s Website, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. You may also access these reports at the SEC’s Website at http://www.sec.gov.

Item 1A. RISK FACTORS

Volatility in the global prices of crude oil, natural gas liquids and natural gas can significantly affect the Company's operating results.

Among the most significant variable factors impacting the Company's results of operations are the sales prices for crude oil and natural gas that it produces. The indices against which much of the Company's production is priced were volatile both in 2019 and 2018 (albeit to a lesser extent in 2019 versus 2018). Crude oil prices in 2019 and 2018 were higher than those in years 2015 to 2017 but were significantly lower than prices in 2013 and 2014. Sales prices for crude oil and natural gas can be significantly different in U.S. markets compared to other international markets.

West Texas Intermediate (WTI) crude oil prices averaged approximately $57 in 2019, compared to $65 in 2018, $51 in 2017, and $43 per barrel in 2016. As of February 25, 2020 closing, the NYMEX WTI forward curve price for April through December 2020 was $50. The closing price for WTI at the end of 2019 was approximately $60 per barrel. Certain U.S. and Canadian crude oils are priced from oil indices other than WTI, and these indices are influenced by different supply and demand forces than those that affect the WTI prices. The most common crude oil indices used to price the Company's crude include Magellan East Houston (MEH), Mars, Louisiana Light Sweet (LLS), and Brent.

The average New York Mercantile Exchange (NYMEX) natural gas sales price was $2.52 in 2019, compared to $3.12 per million British Thermal Units (MMBTU) in 2018, $2.96 per MMBTU in 2017, and $2.48 per MMBTU in 2016. The closing price for NYMEX natural gas as of December 31, 2019, was $2.19 per MMBTU. The Company also has exposure to the Canadian benchmark natural gas price, AECO, which averaged $1.33 per MMBTU in 2019. The Company has entered into certain forward fixed price contracts as detailed in the Outlook section on page 41 and certain variable netback contracts providing exposure to Malin and Chicago City Gate prices.

The Company cannot predict how changes in the sales prices of oil and natural gas will affect the results of operations in future periods. In 2019, the Company hedged a portion of its exposure to the effects of changing prices of crude oil and natural gas by selling forwards, swaps and other forms of derivative contracts. The Company markets a portion of Canadian natural gas production to locations other than AECO and through physical forward sales.

See Note M – Financial Instruments and Risk Management for additional information on the derivative instruments used to manage certain risks related to commodity prices.

Low oil and natural gas prices may adversely affect the Company's operations in several ways in the future.

Lower oil and natural gas prices adversely affect the Company in several ways:

- Lower sales value for the Company's oil and natural gas production reduces cash flows and net income.
- Lower cash flows may cause the Company to reduce its capital expenditure program, thereby potentially restricting its ability to grow production and add proved reserves.
- Lower oil and natural gas prices could lead to impairment charges in future periods, therefore reducing net income.
- Reductions in oil and natural gas prices could lead to reductions in the Company's proved reserves in future years. Low prices could make a portion of the Company's proved reserves uneconomic, which in turn could lead to the removal of certain of the Company's year-end reported proved oil reserves in future periods. These reserve reductions could be significant.
- In order to manage the potential volatility of cash flows and credit requirements, we maintain appropriate bank credit facilities. Inability to access, renew or replace such credit facilities or access other sources of funding as they mature would negatively impact our liquidity.
- Lower prices for oil and natural gas could cause the Company to lower its dividend because of lower cash flows.

Certain of these effects are further discussed in risk factors that follow.

Murphy's commodity price risk management may limit the Company's ability to fully benefit from potential future price increases for oil and natural gas.

The Company, from time to time, enters into various contracts to protect its cash flows against lower oil and natural gas prices. Because of these contracts, if the prices for oil and natural gas increase in future periods, the Company will not fully benefit from the price improvement on all production.

Murphy operates in highly competitive environments which could adversely affect it in many ways, including its profitability, cash flows and its ability to grow.

Murphy operates in the oil and natural gas industry and experiences competition from other oil and natural gas companies, which include state-owned foreign oil companies, major integrated oil companies, private equity investors and independent producers of oil and natural gas. Many of the state-owned and major integrated oil companies and some of the independent producers that compete with the Company have substantially greater resources than Murphy.

In addition, the oil industry as a whole competes with other industries in supplying energy requirements around the world. Murphy competes, among other things, for valuable acreage positions, exploration licenses, drilling equipment and talent.

Murphy could face emerging long-term challenges to the fossil fuels business model.

As environmental and social trends change towards less carbon intensive energy sources, Murphy’s business model may come under more pressure from changing global demands for non-fossil fuel energy sources. As part of Murphy’s strategy review process, the Company reviews hydrocarbon demand forecasts and assesses the impact on its business model and plans. The Company also has significant natural gas reserves which emit lower carbon compared to oil and liquids.

The issue of climate change has caused considerable attention to be directed towards initiatives to reduce global greenhouse gas emissions. An international climate agreement (the “Paris Agreement”) was agreed to at the 2015 United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement entered into force in November 2016, however, after originally entering the agreement the U.S., in 2017 subsequently withdrew from this agreement. The U.S. remains the only country, of the original signatories, not part of the Paris Agreement. It is possible that the Paris Agreement, if fully implemented, and other such initiatives, including foreign, federal and state environmental rules or regulations related to greenhouse gas emissions and climate change, may reduce the demand for crude oil and natural gas globally. In addition to regulatory risk, other market and social initiatives such as public and private initiatives that aim to subsidize the development of non-fossil fuel energy sources, may reduce the competitiveness of carbon-based fuels, such as oil and gas. While the magnitude of any reduction in hydrocarbon demand is difficult to predict, such a development could adversely impact the Company and other companies engaged in the exploration and production business. The Company continually monitors the global climate change agenda initiatives and plans accordingly based on its assessment of such initiatives on its business.

Exploration drilling results can significantly affect the Company’s operating results.

The Company drills exploratory wells which subjects its exploration and production operating results to exposure to dry holes expense, which may have adverse effects on, and create volatility for, the Company’s results of operations. In response to lower oil prices in recent years, the Company has reduced its exploration program from pre-2015 levels and currently plans to participate in approximately four exploration wells per year. In 2019, the Company drilled exploration wells in the U.S. Gulf of Mexico, Vietnam, and Mexico and experienced a 100% success rate. The Company has budgeted $100 million for its 2020 exploration program, which includes two operated wells offshore Mexico, two non-operated wells (one well in the U.S. Gulf of Mexico, one well in Brazil; subject to rig availability/timing) and other exploratory spend.

If Murphy cannot replace its oil and natural gas reserves, it may not be able to sustain or grow its business.

Murphy continually depletes its oil and natural gas reserves as production occurs. To sustain and grow its business, the Company must successfully replace the oil and natural gas it produces with additional reserves. Therefore, it must create and maintain a portfolio of good prospects for future reserves additions and production. The Company does this by obtaining rights to explore for, develop and produce hydrocarbons in prospective areas. In addition, it must find, develop and produce and/or acquire reserves at a competitive cost to be successful in the long-term. Murphy’s ability to operate profitably in the exploration and production business, therefore, is dependent on its ability to find (and/or acquire), develop and produce oil and natural gas reserves at costs that are less than the realized sales price for these products.

In 2019, the Company, completed a transaction with LLOG Exploration Offshore L.L.C. and LLOG Bluewater Holdings, L.L.C., (LLOG), whereby the Company acquired 26 blocks in the Mississippi Canyon and Green Canyon areas of the Gulf of Mexico. In addition, the Company acquired incremental ownership in the Chinook field in the Gulf of Mexico. In 2018, the Company entered into a transaction among Murphy, PAI and MP Gulf of Mexico, LLC (MP GOM), whereby the Company through its interest in MP GOM acquired an 80% interest in PAI Gulf of Mexico producing Assets (Cascade, Chinook, Lucius, St. Malo, Cottonwood, South Marsh Island, Northwestern, and South Hadrian fields) and its interests in exploration blocks in the U.S. Gulf of Mexico to MP GOM.

Murphy's proved reserves are based on the professional judgment of its engineers and may be subject to revision.

Proved reserves of crude oil, natural gas liquids (NGL) and natural gas included in this report on pages 94 through 102 have been prepared according to the Securities and Exchange (SEC) guidelines by qualified Company personnel or qualified independent engineers based on an unweighted average of crude oil, NGL and natural gas prices in effect at the beginning of each month of the respective year as well as other conditions and information available at the time the estimates were prepared. Estimation of reserves is a subjective process that involves professional judgment by engineers about volumes to be recovered in future periods from underground oil and natural gas reservoirs. Estimates of economically recoverable crude oil, NGL and natural gas reserves and future net cash flows depend upon a number of variable factors and assumptions, and consequently, different engineers could arrive at different estimates of reserves and future net cash flows based on the same available data and using industry accepted engineering practices and scientific methods.

Murphy's actual future oil and natural gas production may vary substantially from its reported quantity of proved reserves due to a number of factors, including:

- Oil and natural gas prices which are materially different from prices used to compute proved reserves
- Operating and/or capital costs which are materially different from those assumed to compute proved reserves
- Future reservoir performance which is materially different from models used to compute proved reserves, and
- Governmental regulations or actions which materially impact operations of a field.

The Company's proved undeveloped reserves represent significant portions of total proved reserves. As of December 31, 2019, and including noncontrolling interests, approximately 46% of the Company's crude oil and condensate proved reserves, 50% of natural gas liquids proved reserves and 38% of natural gas proved reserves are undeveloped. The ability of the Company to reclassify these undeveloped proved reserves to the proved developed classification is generally dependent on the successful completion of one or more operations, which might include further development drilling, construction of facilities or pipelines, and well workovers.

The discounted future net revenues from our proved reserves as reported on pages 107 and 108 should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles (GAAP), the estimated discounted future net revenues from our proved reserves are based on an unweighted average of the oil and natural gas prices in effect at the beginning of each month during the year. Actual future prices and costs may be materially higher or lower than those used in the reserves computations.

In addition, the 10% discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under GAAP is not necessarily the most appropriate discount factor based on our cost of capital, the risks associated with our business and the risk associated with the industry in general.

Capital financing may not always be available to fund Murphy's activities; and interest rates could impact cash flows.

Murphy usually must spend and risk a significant amount of capital to find and develop reserves before revenue is generated from production. Although most capital needs are funded from operating cash flow, the timing of cash flows from operations and capital funding requirements may not always coincide, and the levels of cash flow generated by operations may not fully cover capital funding requirements, especially in periods of low commodity prices. Therefore, the Company maintains financing arrangements with lending institutions to meet certain funding needs. The Company periodically renews these financing arrangements based on foreseeable financing needs or as they expire. In November 2018, the Company entered into a $1.6 billion revolving credit facility (the "RCF"). The RCF is a senior unsecured guaranteed facility and will expire in November 2023.

Amounts drawn under the RCF may bear interest in relation to LIBOR, depending on our selection of rates. In July 2017, the Financial Conduct Authority in the U.K. announced a desire to phase out LIBOR as a benchmark by the end of 2021. Financial industry working groups are developing replacement rates and methodologies to transition existing agreements that depend on LIBOR as a reference rate; however, we can provide no assurance that market-accepted rates and transition methodologies will be available and finalized at the time of LIBOR cessation. If clear market standards and transition methodologies have not developed by the time LIBOR becomes unavailable, we may have difficulty reaching agreement on acceptable replacement rates under the RCF. If we are unable to negotiate replacement rates on favorable terms, it could have a material adverse effect on our earnings and cash flows.

In November 2019, the Company issued $550 million of new notes that bear interest at a rate of 5.875% and mature on December 1, 2027 and repurchased and canceled $239.7 million of the Company's 4.00% notes due 2022 and $281.6 million of the Company's 4.45% notes due 2022 (originally issued as 3.70% notes due 2022) during November and December 2019.

The Company's ability to obtain additional financing is also affected by the Company's debt credit ratings and competition for available debt financing. A ratings downgrade could materially and adversely impact the Company's ability to access debt markets, increase the borrowing cost under the Company's credit facility and the cost of future debt, and potentially require the Company to post additional letters of credit or other forms of collateral for certain obligations.

Further, changes in economic environments and investors' view of risk of the exploration and production industry could adversely impact interest rates. This could result in higher interest costs on capital funding lowering net income and cash-flows. Murphy partially manages this risk through borrowing at fixed rates where-ever possible; however, rates determined when refinancing or new capital is required are partly determined through factors outside of Murphy's control, such as centrally (federal government) set interest rates and investors' view of the exploration and production industry.

See Note H – Financing Arrangements and Debt for information regarding the Company's outstanding debt and other commitments as of December 31, 2019 and the terms associated therewith.

Murphy's operations could be adversely affected by changes in foreign exchange rates.

The Company's worldwide operational scope exposes it to risks associated with foreign currencies. Most of the Company's business is transacted in U.S. dollars, and therefore the Company and most of its subsidiaries are U.S. dollar functional entities for accounting purposes. However, the Canadian dollar is the functional currency for all Canadian operations. This exposure to currencies other than the U.S. dollar functional currency can lead to impacts on consolidated financial results from foreign currency translation. On occasions, the Canadian business may hold assets or incur liabilities denominated in a currency which is not Canadian dollars which could lead to exposure to foreign exchange rate fluctuations. See also Note M – Financial Instruments and Risk Management in the Notes to Consolidated Financial Statements for additional information on derivative contracts.

The costs and funding requirements related to the Company's retirement plans are affected by several factors.

A number of actuarial assumptions impact funding requirements for the Company's retirement plans. The most significant of these assumptions include return on assets, long-term interest rates and mortality. If the actual results for the plans vary significantly from the actuarial assumptions used, or if laws regulating such retirement plans are changed, Murphy could be required to make more significant funding payments to one or more of its retirement plans in the future and/or it could be required to record a larger liability for future obligations in its Consolidated Balance Sheet.

Murphy has limited control over supply chain costs.

The Company often experiences pressure on its operating and capital expenditures in periods of strong crude oil and natural gas prices because an increase in exploration and production activities due to high oil and natural gas sales prices generally leads to higher demand for, and consequently higher costs for, goods and services in the oil and natural gas industry. The increase in oil prices in 2017 and 2018 (compared to 2015 to 2016) led to some upward inflation pressure in oil field goods and service costs during those years. In 2019 the cost of goods and services in the oil and natural gas industry were stable.

Murphy is sometimes reliant on joint venture partners for operating assets, and/or funding development projects and operations.

Certain of the Company's major oil and natural gas producing properties are operated by others. Therefore, Murphy does not fully control all activities at certain of its revenue generating properties. During 2019, approximately 16% of the Company's total production was at fields operated by others, while at December 31, 2019, approximately 14% of the Company's total proved reserves were at fields operated by others.

Additionally, the Company relies on the availability of transportation and processing facilities that are often owned and operated by others. These third-party systems and facilities may not always be available to the Company, and if available, may not be available at a price that is acceptable to the Company.

Some of Murphy's development projects entail significant capital expenditures and have long development cycle times. As a result, the Company's partners must be able to fund their share of investment costs through the development cycle, through cash flow from operations, external credit facilities, or other sources, including financing arrangements. Murphy's partners are also susceptible to certain of the risk factors noted herein, including, but not limited to, commodity price, fiscal regime changes, government project approval delays, regulatory changes, credit downgrades and regional conflict. If one or more of these factors negatively impacts a project partners' cash flows or ability to obtain adequate financing, it could result in a delay or cancellation of a project, resulting in a reduction of the Company's reserves and production, which negatively impacts the timing and receipt of planned cash flows and expected profitability.

Murphy's Information Technology environment may be exposed to cyber threats.

In recent years the oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, and production activities. We depend on these technologies to estimate quantities of oil and natural gas reserves, process and record financial and operating data, analyze seismic and drilling information, communicate with our employees and third-party partners, and conduct many of our activities.

Maintaining the security of the technology and preventing unauthorized access is critical given increasing global threats from cybercrime. The Company's approach focuses on cyber risk assessment, asset protection, eradicating security vulnerabilities, security education and security awareness.

Specifically, where we are reliant on third parties, we add in contract provisions to protect ourselves so that the third party needs to comply with our security policies, notify us of breaches timely and jointly perform risk assessments. We incorporate network access controls (include remote access security) to prevent unauthorized devices connecting to our network. As the sophistication of cyber-attacks continues to evolve, we may be required to dedicate additional resources to continue to modify or enhance our protective measures, or to investigate and remediate any vulnerabilities to cyber-attacks.

Potential federal or state regulations could increase the Company's costs and/or restrict operating methods, which could adversely affect its production levels.

The Company's operations are subject to numerous environmental and occupational health and safety laws and regulations at the international, federal, provincial, state, tribal, and local levels. These laws and associated requirements can impose operational controls and/or siting constraints on our business. These laws and regulations can result in additional capital and operating expenditures.

The Company's onshore North America oil and natural gas production is dependent on a technique known as hydraulic fracturing whereby water, sand and certain chemicals are injected into deep oil and natural gas bearing reservoirs in North America. This process occurs thousands of feet below the surface and creates fractures in the rock formation within the reservoir which enhances migration of oil and natural gas to the wellbore. The Company primarily uses this technique in the Eagle Ford Shale in South Texas and in Western Canada. In June 2011, the State of Texas adopted a law requiring public disclosure of certain information regarding the components used in the hydraulic fracturing process. The Provinces of British Columbia and Alberta have also issued regulations related to various aspects of hydraulic fracturing activities under their jurisdictions. It is possible that the states, the U.S., Canadian provinces and certain municipalities adopt further laws or regulations which could render the process unlawful, less effective or drive up its costs. If any such action is taken in the future, the Company's production levels could be adversely affected, or its costs of drilling and completion could be increased. Once new laws and/or regulations have been enacted and adopted, the costs of compliance are appraised.

Hydraulic fracturing operations subject the Company to operational risks inherent in the drilling and production of oil and natural gas. These risks include underground migration or surface spillage due to releases of oil, natural gas, formation water or well fluids, as well as any related surface or groundwater contamination, including from petroleum constituents or hydraulic fracturing chemical additives. Ineffective containment of surface spillage and surface or groundwater contamination resulting from hydraulic fracturing operations, including from petroleum constituents or hydraulic fracturing chemical additives, could result in environmental pollution, remediation expenses and third-party claims alleging damages, which could adversely affect the Company's financial condition and results of operations. In addition, hydraulic fracturing requires significant quantities of water; the wastewater from oil and natural gas operations is often disposed of through underground injection. Certain increased seismic activities have been linked to underground water injection. Any diminished access to water for use in the hydraulic fracturing process, any inability to properly dispose of wastewater, or any further restrictions placed on wastewater, could curtail the Company's operations or otherwise result in operational delays or increased costs.

In April 2016, the U.S. Department of the Interior's (DOI) Bureau of Safety and Environmental Enforcement (BSEE) enacted broad regulatory changes related to Gulf of Mexico well design, well control, casing, cementing, real-time monitoring, and subsea containment, among other items. These changes are known broadly as the Well Control Rule, and amendments to this rule were enacted in May 2019. Compliance is required over the next several years. Some provisions remain for which BSEE future enforcement actions are unclear, so risk of impact leading to increased future cost on the Company's Gulf of Mexico operations remains.

In July 2016, the DOI's Bureau of Ocean Energy Management (BOEM) issued an updated Notice to Lessees and Operators (NTL) providing details on revised procedures BOEM used to determine a lessee's ability to carry out decommissioning obligations for activities on the Outer Continental Shelf (OCS), including the Gulf of Mexico. This revised policy became effective in September 2016 and instituted new criteria by which the BOEM will evaluate the financial strength and reliability of lessees and operators active on the OCS. If the BOEM determines under the revised policy that a company does not have the financial ability to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance. In January 2017 BOEM extended the implementation timeline for the NTL by six months for properties which have co-lessees, and in February 2017 BOEM withdrew sole liability orders issued in December 2016 to allow time for the new administration to review the financial assurance program for decommissioning. Although the Company believes a potential new BOEM policy could lead to increased costs for its Gulf of Mexico operations, it does not currently believe that the impact will be material to its operations in the Gulf of Mexico.

In the future, BOEM and/or BSEE may impose new and more stringent offshore operating regulations which may adversely affect the Company's operations.

Murphy's operations and earnings have been and will continue to be affected by worldwide political developments.

Many governments, including those that are members of the Organization of Petroleum Exporting Countries (OPEC), unilaterally intervene at times in the market of crude oil and natural gas produced in their countries through such actions as changing fiscal regimes (including corporate income tax rates), setting prices, determining rates of production, and controlling who may buy and sell the production.

Changes in government fiscal policies can lead to earnings volatility. For example, in 2018, Murphy Oil's net income included a favorable income tax adjustment of $135.7 million related to the 2017 Tax Act enacted on December 22, 2017. The $135.7 million adjustment, primarily related to the reinstatement of a deferred tax asset for 2017 net operating losses, which in 2017, was assumed utilized against the deemed repatriation. For the year ended December 31, 2017, Murphy recorded a tax expense of $274.0 million directly related to the impact of the 2017 Tax Act. The charge includes the impact of a deemed repatriation of accumulated foreign earnings and the re-measurement of deferred tax assets and liabilities.

As of December 31, 2019, approximately 0.1%of the Company's proved reserves, as defined by the SEC, were located in countries other than the U.S. and Canada. In addition, prices and availability of crude oil, natural gas and refined products could be influenced by political factors and by various governmental policies to restrict or increase petroleum usage and supply. Other governmental actions that could affect Murphy's operations and earnings include expropriation, tax changes, royalty increases, redefinition of international boundaries, preferential and discriminatory awarding of oil and natural gas leases, restrictions on drilling and/or production, restraints and controls on imports and exports, safety, and relationships between employers and employees. Governments could also initiate regulations concerning matters such as currency fluctuations, currency conversion, protection and remediation of the environment, and concerns over the possibility of global warming caused by the production and use of hydrocarbon energy.

A number of non-governmental entities routinely attempt to influence industry members and government energy policy in an effort to limit industry activities, such as hydrocarbon production, drilling and hydraulic fracturing with the desire to minimize the emission of greenhouse gases such as carbon dioxide, which may harm air quality, and to restrict hydrocarbon spills, which may harm land and/or groundwater.

Additionally, because of the numerous countries in which the Company operates, certain other risks exist, including the application of the U.S. Foreign Corrupt Practices Act, the Canada Corruption of Foreign Officials Act, the Brazil Clean Companies Act, the Mexico General Law of the National Anti-Corruption System, and other similar anti-corruption compliance statutes.

It is not possible to predict the actions of governments and hence the impact on Murphy's future operations and earnings.

Murphy's business is subject to operational hazards, security risks and risks normally associated with the exploration and production of oil and natural gas.

The Company operates in urban and remote, and sometimes inhospitable, areas around the world. The occurrence of an event, including but not limited to acts of nature such as hurricanes, floods, earthquakes (and other forms of severe weather), mechanical equipment failures, industrial accidents, fires, explosions, acts of war, civil unrest, piracy and acts of terrorism could result in the loss of hydrocarbons and associated revenues, environmental pollution or contamination, personal injury, (including death), and property damages for which the Company could be deemed to be liable and which could subject the Company to substantial fines and/or claims for punitive damages. This risk extends to actions and operational hazards of other operators in the industry, which may also impact the Company.

The location of many of Murphy’s key assets causes the Company to be vulnerable to severe weather, including hurricanes and tropical storms. Many of the Company’s offshore fields are in the U.S. Gulf of Mexico, where hurricanes and tropical storms can lead to shutdowns and damages. The U.S. hurricane season runs from June through November. Moreover, it should be noted that scientists have predicted that increasing concentrations of greenhouse gases in the earth’s atmosphere may produce climate changes that increase significant weather events, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If such effects were to occur, our operations could be adversely affected. Although the Company maintains insurance for such risks as described elsewhere in this Form 10-K report, due to policy deductibles and possible coverage limits, weather-related risks are not fully insured.

Murphy’s insurance may not be adequate to offset costs associated with certain events and there can be no assurance that insurance coverage will continue to be available in the future on terms that justify its purchase.

Murphy maintains insurance against certain, but not all, hazards that could arise from its operations. The Company maintains liability insurance sufficient to cover its share of gross insured claim costs up to approximately $500 million per occurrence and in the annual aggregate. Generally, this insurance covers various types of third-party claims related to personal injury, death and property damage, including claims arising from “sudden and accidental” pollution events. The Company also maintains insurance coverage with an additional limit of $400 million per occurrence ($875 million for Gulf of Mexico claims), all or part of which could apply to certain sudden and accidental pollution events. These policies have deductibles ranging from $10 million to $25 million. The occurrence of an event that is not insured or not fully insured could have a material adverse effect on the Company’s financial condition and results of operations in the future.

Lawsuits against Murphy and its subsidiaries could adversely affect its operating results.

The Company or certain of its consolidated subsidiaries are involved in numerous legal proceedings, including lawsuits for alleged personal injuries, property damages and other business-related matters. Certain of these claims may take many years to resolve through court and arbitration proceedings or negotiated settlements. In the opinion of management and based upon currently known facts and circumstances, the currently pending legal proceedings are not expected, individually or in the aggregate, to have a material adverse effect upon the Company’s operations or financial condition.

The Company is exposed to credit risks associated with sales of certain of its products to customers and associated with its operating partners.

Although Murphy limits its credit risk by selling its products to numerous entities, it still, at times, carries credit risk from its customers. For certain oil and natural gas properties operated by the Company, other companies which own partial interests may not be able to meet their financial obligation to pay for their share of capital and operating costs as they come due. The inability of a purchaser of the Company’s oil or natural gas or a partner of the Company to meet their respective payment obligations to the Company could have an adverse effect on Murphy’s future earnings and cash flows.

Item 1B. UNRESOLVED STAFF COMMENTS

The Company had no unresolved comments from the staff of the U.S. Securities and Exchange Commission as of December 31, 2019.

Item 2. PROPERTIES

Descriptions of the Company's oil and natural gas properties are included in Item 1 of this Form 10-K report beginning on page 1. Information required by the Securities Exchange Act Industry Guide No. 2 can be found in the Supplemental Oil and Gas Information section of this Annual Report on Form 10-K on pages 94 to 109 and in Note G – Property, Plant and Equipment beginning on page 68.

Item 3. LEGAL PROCEEDINGS

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 matters referred to in this item is not expected to have a material adverse effect on the Company's net income or loss, financial condition or liquidity in a future period.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Information about our Executive Officers

Present corporate office, length of service in office and age at February 1, 2020 of each of the Company's executive officers are reported in the following listing. Executive officers are elected annually, but may be removed from office at any time by the Board of Directors.

Roger W. Jenkins – Age 58; President and Chief Executive Officer since August 2013. Mr. Jenkins served as Chief Operating Officer from June 2012 to August 2013.

David R. Looney – Age 63; Executive Vice President and Chief Financial Officer since March 2018. Mr. Looney joined the Company following a broad range of leadership roles at both offshore deepwater Gulf of Mexico and U.S. onshore unconventional exploration and production companies.

Walter K. Compton – Age 57; Executive Vice President and General Counsel since February 2014. Mr. Compton was Senior Vice President and General Counsel from March 2011 to February 2014.

Eric M. Hambly – Age 45; Executive Vice President, Onshore since September 2018. Mr. Hambly served as Senior Vice President, U.S. Onshore from 2016 to September 2018.

Michael K. McFadyen – Age 52; Executive Vice President, Offshore since September 2018. Mr. McFadyen has also served as Executive Vice President, Onshore of the Company's exploration and production subsidiary from 2011 to 2017.

Thomas J. Mireles – Age 47; Senior Vice President, Technical Services (Health, Safety, Environment, Information Technology and Procurement) since September 2018. Mr. Mireles also served as the Senior Vice President, Eastern Hemisphere from 2016 to September 2018.

E. Ted Botner – Age 55; Vice President, Law and Secretary since March 2015. Mr. Botner was Secretary and Manager, Law from August 2013 to March 2015.

John B. Gardner – Age 51; Vice President and Treasurer since March 2015. Mr. Gardner served as Treasurer from August 2013 to March 2015.

Christopher D. Hulse – Age 41, Vice President and Controller since June 2017. Mr. Hulse was Vice President, Finance, Onshore from September 2015 to June 2017.

Barry F.R. Jeffery – Age 61; Vice President, Health, Safety and Environment since June 2017. Mr. Jeffery was Vice President, Insurance, Security and Risk from July 2015 to June 2017.

Maria A. Martinez – Age 45; Vice President, Human Resources and Administration since September 2018. Ms. Martinez was the Vice President, Human Resources from 2013 to September 2018.

Louis W. Utsch – Age 54; Vice President, Tax since January 2018. Mr. Utsch joined the Company following over 20 years of corporate tax experience at Big Four accounting firms as well as more than a decade of work experience in the oil and natural gas industry.

Kelly L. Whitley – Age 54; Vice President, Investor Relations and Communications since July 2015.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company's Common Stock is traded on the New York Stock Exchange using "MUR" as the trading symbol. There were 2,265 stockholders of record as of December 31, 2019. Information on dividends per share by quarter for 2019 and 2018 are reported on page 110 of this Form 10-K report.

Issuer Purchase of Equity Securities:

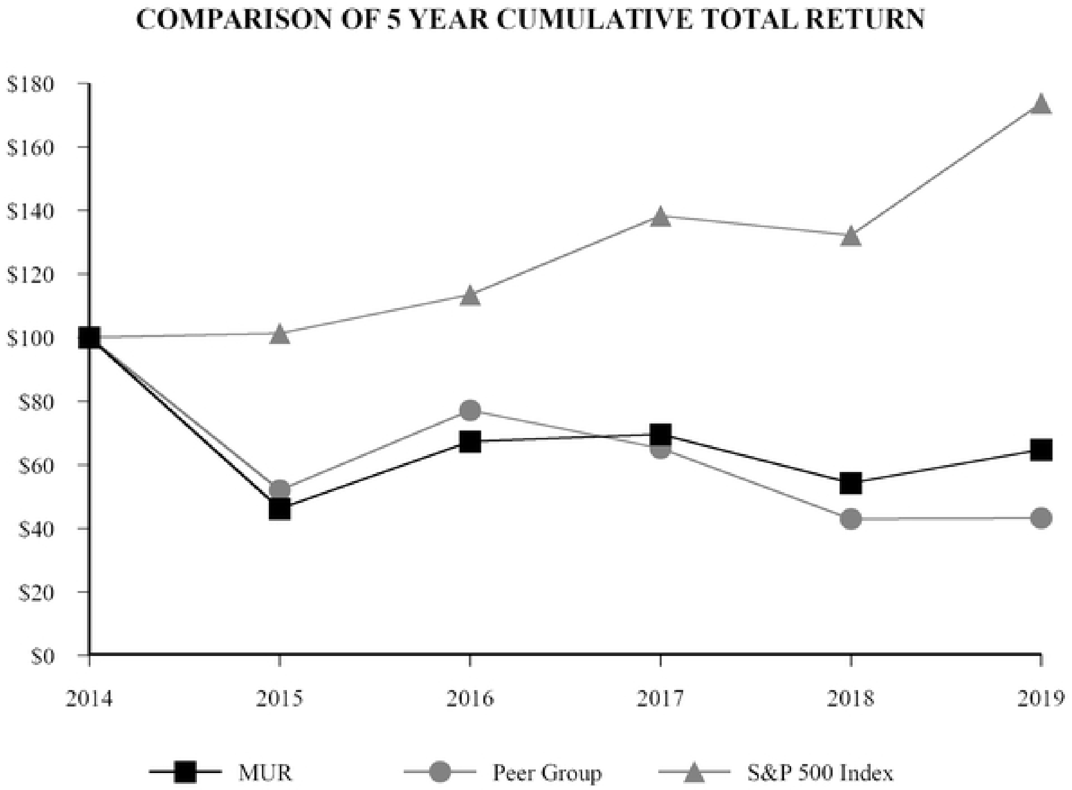
In March 2019, the Company's Board of Directors authorized a stock repurchase plan of up to $500 million of Murphy Common Stock. Maximum approximate values reported represent amounts at end of month. During 2019, the Company repurchased 20.7 million shares outstanding for $499.9 million, marking the completion of the $500 million share repurchase program.

The following table summarizes repurchases of our common stock occurring in the fourth quarter 2019.

Period	Total Number of Share Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under Plans or Programs
October 1 through October 31, 2019	4,300,578	21.83	4,300,578	—
November 1 through November 30, 2019	—	—	—	—
December 1 through December 31, 2019	—	—	—	—

SHAREHOLDER RETURN PERFORMANCE PRESENTATION

The following graph presents a comparison of cumulative five-year shareholder returns (including the reinvestment of dividends) as if a $100 investment was made on December 31, 2014 in the Company, the Standard & Poor's 500 Stock Index (S&P 500 Index), and the Company's peer group. The companies in the peer group included Apache Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Co., CNX Resources Corporation, Devon Energy Corporation, Ovintiv Inc. (formerly Encana Corporation), Hess Corporation, Marathon Oil Corporation, Matador Resources Company, Noble Energy, Inc., Range Resources Corporation, SM Energy Company, Southwestern Energy Company and Whiting Petroleum Corporation. This performance information is "furnished" by the Company and is not considered as "filed" with this Form 10-K report and it is not incorporated into any document that incorporates this Form 10-K report by reference.



		2014	2015	2016	2017	2018	2019
Murphy Oil Corporation	$	100	46	67	70	54	65
Peer Group		100	52	77	65	43	43
S&P 500 Index		100	101	114	138	132	174

Item 6. SELECTED FINANCIAL DATA

The following table contains selected financial data which highlight certain trends in Murphy's financial condition and results of operations for the last five years. The income statement data for the last three years excludes Malaysia as the Malaysia operations were classified as discontinued operations effective January 1, 2019. See Notes E and G for more information regarding the results of operations and the sale of Malaysia.

(Thousands of dollars except per share data)

Results of Operations for the Year	2019	2018	2017	2016	2015
Revenue from sales to customers	$ **2,817,111**	1,806,473	1,300,464	1,862,891	2,787,116
Net cash provided by continuing operations	**1,489,105**	749,395	613,351	600,795	1,183,369
Income (loss) from continuing operations	**188,815**	169,138	(553,015)	(273,943)	(2,255,772)
Net income (loss) attributable to Murphy	**1,149,732**	411,094	(311,789)	(275,970)	(2,270,833)
Cash dividends – diluted	**163,669**	173,044	172,565	206,635	244,998
Per Common share – diluted					
Income (loss) from continuing operations	**0.52**	0.92	(3.21)	(1.59)	(12.94)
Net income (loss) attributable to Murphy	**6.98**	2.36	(1.81)	(1.60)	(13.03)
Average common shares outstanding (thousands) – diluted	**164,812**	174,209	172,524	172,173	174,351
Cash dividends per Common share	$ **1.00**	1.00	1.00	1.20	1.40
Capital Expenditures for the Year [1]					
Continuing operations					
Exploration and production	$ **2,683,200**	$ 1,818,800	942,500	789,721	2,127,197
Corporate and other	**15,000**	22,700	10,300	21,740	59,886
	2,698,200	1,841,500	952,800	811,461	2,187,083
Discontinued operations	**64,400**	145,800	22,891	—	159
	$ **2,762,600**	1,987,300	975,691	811,461	2,187,242
Financial Condition at December 31					
Current ratio	**1.03**	1.04	1.64	1.04	0.83
Working capital (deficit)	$ **31,538**	33,756	537,396	56,751	(277,396)
Net property, plant and equipment	**9,969,743**	8,432,133	8,220,031	8,316,188	9,818,365
Total assets	**11,718,504**	11,052,587	9,860,942	10,295,860	11,493,812
Long-term debt [2]	**2,803,381**	3,109,318	2,906,520	2,422,750	3,040,594
Murphy shareholders' equity	**5,467,460**	4,829,299	4,620,191	4,916,679	5,306,728
Per share	**35.75**	27.91	26.77	28.55	30.85
Long-term debt – percent of capital employed [3]	**33.9**	39.2	38.6	33.0	36.4
Stockholder and Employee Data at December 31					
Common shares outstanding (thousands)	**152,935**	173,059	172,573	172,202	172,035
Number of stockholders of record	**2,265**	2,324	2,506	2,588	2,713

[1] Capital expenditures include accruals for incurred but unpaid capital activities, while property additions and dry holes in the Statements of Cash Flows are cash-based capital expenditures and do not include capital accruals and geological, geophysical and certain other exploration expenses that are not eligible for capitalization under oil and natural gas accounting rules. 2019 includes $1,261.1 million for proved property acquisitions, primarily related to the LLOG transaction. 2018 includes $794.6 million capital expenditures in relation to the MP GOM transaction.

[2] Long-term debt includes non-current capital lease obligations.

[3] Long-term debt – percent of capital employed is calculated as total long-term debt at the balance sheet date divided by the sum of total long-term debt plus total Murphy shareholders' equity at that date.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Murphy Oil Corporation is a worldwide oil and natural gas exploration and production company. A more detailed description of the Company's significant assets can be found in Item 1 of this Form 10-K report.

Significant Company operating and financial highlights during 2019 were as follows:

- Completed a $500 million share repurchase program. Total shares issued and outstanding reduced by 20.7 million shares, to 152.9 million shares
- Issued $550 million of 5.875 percent senior notes due 2027, the proceeds of which were used to repurchase an aggregate of approximately $521 million of senior notes due 2022
- Operating income from continuing operations of $445.3 million (2018: $215.6 million)
- Completed an oil-weighted Gulf of Mexico acquisition with LLOG (see Business Review for further details)
- Divested Malaysia operations (classified as discontinued operations) and recognized a gain on sale of $985.4 million
- Produced 185,649 barrels of oil equivalent (BOE) per day (173,255 excluding noncontrolling interest, NCI)
- Achieved an overall lease operating expense per BOE of $8.95 (2018: $7.87)
- Excluding acquisitions and divestitures, organically replaced 160% of total proved reserves (172% excluding NCI)
- Improved balance sheet strength with approximately 31.3% net debt to total capital [1]

Throughout this section, the term, 'excluding noncontrolling interest' or 'excluding NCI' refers to amounts attributable to Murphy.

Murphy's continuing operations generate revenue by producing crude oil, natural gas liquids (NGL) and natural gas in the United States, Gulf of Mexico and Canada and then selling these products to customers. The Company's revenue is affected by the prices of crude oil, natural gas and NGL. In order to make a profit and generate cash in its exploration and production business, revenue generated from the sales of oil and natural gas produced must exceed the combined costs of producing these products, depreciation of capital expenditures, and expenses related to exploration, administration, and for capital borrowed from lending institutions and note holders.

Changes in the price of crude oil and natural gas have a significant impact on the profitability of the Company. In 2019 liquids from continuing operations represented 66% of total hydrocarbons produced from continuing operations on an energy equivalent basis. In 2020, the Company's ratio of hydrocarbon production represented by liquids is expected to be 67%. If the prices for crude oil and natural gas are lower in 2020 or beyond, this will have an unfavorable impact on the Company's operating profits. The Company, from time to time, may choose to use a variety of commodity hedge instruments to reduce commodity price risk, including forward sale fixed financial swaps and long-term fixed-price physical commodity sales.

Oil prices weakened in 2019 compared to the 2018 period. The sales price of a barrel of West Texas Intermediate (WTI) crude oil averaged $57.03 in 2019, $64.77 in 2018, and $50.95 in 2017. The WTI index decreased approximately 12% over the prior year.

Murphy's realized crude oil price is generally higher than WTI due to sales of crude oil at/off other market points/prices. The most common crude oil indices used to price the Company's crude include Magellan East Houston (MEH), Louisiana Light Sweet (LLS), Mars, and Brent.

The NYMEX natural gas price per million British Thermal Units (MMBTU) averaged $2.52 in 2019, $3.12 in 2018 and $2.96 in 2017. The 2019 NYMEX natural gas price was lower compared to the 2018 price. NYMEX natural gas prices in 2018 were marginally better than the 2017 price. On an energy equivalent basis, the market continued to discount North American natural gas and NGL compared to crude oil in 2019. Natural gas prices in North America in 2020 have thus far been below the average 2019 levels.

[1] Total capital for purposes of this calculation is Murphy shareholders' equity plus long-term debt less cash.

Results of Operations

Murphy Oil's results of operations, with associated diluted earnings per share (EPS), for the last three years are presented in the following table.

	Years Ended December 31,		
(Millions of dollars, except EPS)	**2019**	2018	2017
Income (loss) from continuing operations before income taxes	$ **203.5**	43.0	(282.9)
Net income (loss) attributable to Murphy	**1,149.7**	411.1	(311.8)
Diluted EPS	**6.98**	2.36	(1.81)
Income (loss) from continuing operations attributable to Murphy	**85.2**	160.7	(553.0)
Diluted EPS	**0.52**	0.92	(3.21)
Income from discontinued operations	**1,064.5**	250.3	241.2
Diluted EPS	**6.46**	1.44	1.40

Results of continuing operations before taxes in 2019 were improved versus 2018, whereas income from continuing operations attributable to Murphy of $85.2 million ($0.52 per diluted share) decreased from income of $160.7 million ($0.92 per diluted share) in 2018. Murphy Oil's net income in 2018 included a favorable income tax adjustment of $135.7 million related to the 2017 Tax Act enacted on December 22, 2017. The $135.7 million adjustment, primarily related to the reinstatement of a deferred tax asset for 2017 net operating losses, which in 2017, was assumed utilized against the deemed repatriation of accumulated foreign earnings.

The results before income tax for 2019 were improved compared to 2018 and favorably impacted by higher revenues (due to higher volumes), lower losses on crude contracts, lower impairment losses; partially offset by lower gain on sale of assets, higher lease operating expenses, higher transportation, gathering and processing expenses, higher depreciation expenses and higher interest charges. Higher lease operating, transportation, gathering and processing expenses and higher depreciation expenses are principally a result of the LLOG acquisition and a full year of the 2018 MP GOM transactions completed in the fourth quarter of 2019. See Exploration and Production section below for further details on 2019 results.

In 2019, income from the Company's discontinued operations was $1,064.5 million, primarily resulting from the gain on sale of the Malaysia business.

Murphy Oil's net income in 2018 vs net loss in 2017 was favorably impacted by higher revenues due to higher realized oil and natural gas sales prices and volumes, higher other operating income (vs 2017 other operating expense, lower exploration expenses, and a favorable income tax adjustment related to the 2017 Tax Act; partially offset by losses on crude contracts, lower gain on sale of assets, higher lease operating expenses and higher depreciation.

On December 22, 2017, the U.S. enacted into legislation the Tax Cuts and Jobs Act (2017 Tax Act). For the year ended December 31, 2017, Murphy recorded a tax expense of $274.0 million directly related to the impact of the 2017 Tax Act. The charge includes the impact of a deemed repatriation of accumulated foreign earnings and the re-measurement of deferred tax assets and liabilities.

Other key performance metrics

The Company uses other operational performance and income metrics to review operational performance. The table below presents Earnings before interest, taxes, depreciation and amortization (EBITDA) and adjusted EBITDA. Management uses EBITDA and adjusted EBITDA internally to evaluate the Company's operational performance and trends between periods and relative to its industry competitors. EBITDA and adjusted EBITDA are non-GAAP financial measures and should not be considered a substitute for Net income (loss) or Cash provided by operating activities as determined in accordance with accounting principles generally accepted in the United States of America. Also presented below is adjusted EBITDA per barrel of oil equivalent sold. Management uses EBITDA per barrel of oil equivalent sold to evaluate the Company's profitability of one barrel of oil equivalent sold in the period. Adjusted EBITDA per barrel of oil equivalent sold is a non-GAAP financial metric.

Other key performance metrics (contd.)

(Millions of dollars, except per barrel of oil equivalents sold)	Year Ended December 31, 2019	2018	2017
Net (loss) income attributable to Murphy (GAAP)	$ **1,149.7**	411.1	(311.8)
Income tax expense (benefit)	**14.7**	(126.1)	270.1
Interest expense, net	**219.3**	180.4	178.3
Depreciation, depletion and amortization expense [1]	**1,076.5**	770.6	751.9
EBITDA attributable to Murphy (Non-GAAP)	**2,460.2**	1,236.0	888.5
Discontinued operations (income) loss	**(1,064.5)**	(250.3)	(241.2)
Accretion of asset retirement obligations	**40.5**	27.1	25.3
Mark-to-market loss (gain) on crude oil derivative contracts	**33.4**	(33.9)	(13.7)
Business development transaction costs	**24.4**	—	—
Write-off of previously suspended exploration wells	**13.2**	4.5	—
Mark-to-market loss (gain) on contingent consideration	**8.7**	(4.8)	—
Seal insurance proceeds	**(8.0)**	(21.0)	—
Foreign exchange losses (gains)	**6.4**	(15.8)	75.1
Ecuador arbitration settlement	**—**	(26.0)	—
Impairment of assets	**—**	20.0	—
Brunei working interest income	**—**	(16.0)	—
Gain on sale of assets	**—**	—	(127.4)
Materials inventory loss	**—**	—	21.0
Adjusted EBITDA attributable to Murphy (Non-GAAP)	$ **1,514.3**	919.8	627.5
Total barrels of oil equivalents sold from continuing operations attributable to Murphy (thousands of barrels)	**63,128**	44,598	40,269
Adjusted EBITDA per barrel of oil equivalents sold	$ **23.99**	20.63	15.58

[1] Depreciation, depletion, and amortization expense used in the computation of EBITDA excludes the portion attributable to the non-controlling interest.

Segment Results – In the following table, the Company's results of operations for the three years ended December 31, 2019, are presented by segment. More detailed reviews of operating results for the Company's exploration and production and other activities follow the table.

A summary of Net income (loss) is presented in the following table.

(Millions of dollars)	2019	2018	2017
Exploration and production – continuing operations			
United States	$ **518.4**	242.9	(12.1)
Canada	**(4.3)**	51.1	112.9
Other International	**(53.5)**	(16.6)	(37.6)
Total exploration and production – continuing operations	**460.6**	277.4	63.2
Corporate and other	**(271.8)**	(108.3)	(616.2)
Income (loss) from continuing operations	**188.8**	169.1	(553.0)
Income from discontinued operations	**1,064.5**	250.3	241.2
Net income (loss) including noncontrolling interest	**1,253.3**	419.4	(311.8)
Net income attributable to noncontrolling interest	**103.6**	8.4	—
Net income (loss) attributable to Murphy	$ **1,149.7**	411.0	(311.8)

A summary of oil and natural gas revenues is presented in the following table.

(Millions of dollars)		2019	2018	2017
United States – Oil and natural gas liquids	$	**2,285.8**	1,277.7	903.7
– Natural gas		**73.9**	53.6	37.9
Canada – Conventional oil and natural gas liquids		**287.4**	302.8	203.7
– Natural gas		**158.4**	166.3	155.1
Other		**11.6**	6.1	—
Total oil and natural gas revenues	$	**2,817.1**	1,806.5	1,300.4

Exploration and Production

Please refer to Schedule 6 – Results of Operations for Oil and Natural Gas Producing Activities in the Supplemental Oil and Natural Gas Information section for supporting tables.

2019 vs 2018

All amounts include amount attributable to a noncontrolling interest in MP GOM and exclude discontinued operations, unless otherwise noted. Also note that weighted average realized prices are reported excluding transportation, gathering and processing costs. Comparative periods are conformed to current presentation.

Exploration and production (E&P) continuing operations recorded a profit of $460.6 million in 2019 compared to a profit of $277.4 million in 2018. The results for 2019 were favorably impacted by higher oil and natural gas volumes, lower exploration expenses, and no impairment charge, partially offset by higher lease operating expenses and transportation, gathering and processing expenses, higher general and administrative expenses, higher depreciation expense, and higher taxes. See below for further details.

Crude oil price realizations averaged $60.27 per barrel in the current year compared to $65.87 per barrel in 2018, a price decrease of 9% year over year. U.S. natural gas realized price per thousand cubic feet (MCF) averaged $2.45 in the current year compared to $3.18 per MCF in 2018, a price decrease of 23% year over year. Canada natural gas realized price per MCF averaged U.S. $1.60 in the current year compared to U.S. $1.71 per MCF in 2018, a price decrease of 6% year over year. Oil and natural gas production costs, including associated production taxes, on a per-unit basis, were $9.66 in 2019 excluding TGP (2018: $9.02), which together with higher oil and natural gas volumes sold, resulted in $247.2 million higher costs in 2019.

United States E&P operations reported earnings of $518.4 million in 2019 compared to income of $242.9 million in 2018. Results were $275.5 million favorable in 2019 compared to the 2018 period due to higher revenues ($1,034.3 million), partially offset by higher depreciation, depletion and amortization ($359.2 million), lease operating expenses ($231 million), transportation, gathering, and processing ($97.7 million), income tax expense ($47.5 million), other operating expense ($29.2 million) and general and administrative (G&A: $25.3 million). Higher revenues were primarily due to higher volumes in the U.S. Gulf of Mexico (as a result of the MP GOM transaction in the fourth quarter of 2018 and the LLOG acquisition in the second quarter of 2019). Higher lease operating, transportation, gathering and processing expenses and depreciation expense were due primarily to higher volumes. Higher income taxes were due to higher profits. Higher other operating expense was due to higher business development, acquisition transaction costs and mark to market valuation on contingent consideration. Higher G&A was due to higher long-term incentive charges.

Canadian E&P operations reported a loss of $4.3 million in 2019 compared to income of $51.1 million in 2018. Results were unfavorable $55.4 million compared to the 2018 period primarily due to lower revenue ($23.5 million), higher lease operating expense ($19.8 million), lower other income ($13.0 million) primarily related to more Seal insurance proceeds received in 2018; and partially offset by lower income tax charges ($17.4 million). Lower revenues were due to lower oil and condensate prices than the prior year and a shut-in at Hibernia in the third quarter, partially offset by higher volumes at Kaybob Duvernay and Tupper Montney. Higher lease operating expenses were due to higher costs at Tupper Montney as a result of transferring a gain on a previous natural gas processing plant sale and lease-back transaction to equity as a result of the implementation of ASC 842 (see Note B). In 2018, this gain was being credited to operating expenses equally over the life of the lease.

Other international E&P operations reported a loss from continuing operations of $53.5 million in 2019 compared to a net loss of $16.6 million in the prior year. The 2019 result included the write-off of previously suspended exploration costs of $13.2 million attributable to the CM-1X and the CT-1X wells (originally drilled in 2017) in Vietnam and lower revenues from Brunei ($10.6 million), and lower tax benefits ($12.9 million).

2018 vs 2017

E&P continuing operations recorded a profit of $277.4 million in 2018 compared to a profit of $63.2 million in 2017. The results for 2018 were favorably impacted by higher revenues due to higher realized oil and natural gas sales prices and volumes, lower gain on sale of assets, lower other exploration expenses, and lower other operating expenses, partially offset by higher lease operating expenses, higher depreciation expense, non-recurring impairment expense in 2018 and higher taxes.

Crude oil price realizations averaged $65.87 per barrel in the current year compared to $51.51 per barrel in 2017, a price increase of 28% year over year. U.S. natural gas realized price per thousand cubic feet (MCF) averaged $3.18 in 2018 compared to $2.96 per MCF in 2017, a price increase of 7% year over year. Canada natural gas realized price per MCF averaged U.S.$1.71 in the current year compared to U.S. $2.11 per MCF in 2017, a price decrease of 19% year over year. Oil and natural gas production costs, including associated production taxes, on a per-unit basis, were $9.02 in 2018 (2017: $8.52), which together with higher oil and natural gas volumes sold, resulted in $62.9 million higher costs in 2018.

United States E&P operations reported earnings of $242.9 million in 2018 compared to a net loss of $12.1 million in 2017. Results were $255.0 million favorable in the 2018 period compared to the 2017 period due to higher revenues ($360.0 million), lower depreciation ($26.8 million), and lower G&A ($12.9 million), partially offset by higher lease operating expenses ($32.1 million), higher dry hole costs ($17.9 million, primarily related to the write-off of the King Cake well in the Gulf of Mexico), an impairment charge related to select Midland properties ($20.0 million), and higher income taxes ($65.6 million). Higher revenues were primarily due to higher realized prices and contribution from new volumes from the MP GOM transaction, 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 $51.1 million in 2018 compared to earnings of $112.9 million in the 2017 period. Results were unfavorable $61.8 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 $34.6 million in the 2018 period compared to the 2017 period due to higher revenue ($85.5 million), and insurance proceeds ($21.3 million), partially offset by higher lease operating expense ($21.6 million), higher depreciation ($47.1 million) and higher taxes ($6.5 million). Higher revenues were a result of both higher volumes at the Tupper Montney, Kaybob Duvernay and Placid Montney 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.

Other international E&P operations reported a loss from continuing operations of $16.6 million in 2018 compared to a net loss of $37.6 million in the 2017 period. The loss was $21.0 million lower in the 2018 period versus 2017 primarily due to the recording of past profits ($21.6 million) relating to the working interest in Block CA1 in Brunei, and lower exploration costs ($16.2 million), partially offset by lower tax benefits on investments in foreign areas ($18.2 million). The Brunei income follows the signing of the Brunei participation agreement on July 4, 2018, which enables the Company the right to claim its proportional share of revenue since inception as well as the obligation to settle the related past operating and capital expenditure costs since inception. In addition, ongoing current Brunei revenue is now being reported.

Table of Contents

The following table contains hydrocarbons produced during the three years ended December 31, 2019.

Barrels per day unless otherwise noted		**2019**	2018	2017
Continuing operations				
Net crude oil and condensate				
United States	Onshore	**34,578**	31,787	34,649
	Gulf of Mexico [1]	**66,823**	18,702	11,551
Canada	Onshore	**6,329**	5,690	3,004
	Offshore	**6,543**	6,701	8,091
Other		**469**	558	150
Total net crude oil and condensate - continuing operations		**114,742**	63,438	57,445
Net natural gas liquids				
United States	Onshore	**5,731**	6,578	6,867
	Gulf of Mexico [1]	**4,894**	1,147	947
Canada	Onshore	1,263	1,073	508
Total net natural gas liquids - continuing operations		**11,888**	8,798	8,322
Net natural gas – thousands of cubic feet per day				
United States	Onshore	**30,692**	31,832	32,629
	Gulf of Mexico [1]	**52,068**	14,356	11,901
Canada	Onshore	**271,355**	266,416	226,218
Total net natural gas - continuing operations		**354,115**	312,604	270,748
Total net hydrocarbons - continuing operations including NCI [2,3]		**185,649**	124,337	110,892
Noncontrolling interest				
Net crude oil and condensate – barrels per day		**(11,226)**	(1,134)	—
Net natural gas liquids – barrels per day		**(507)**	(24)	—
Net natural gas – thousands of cubic feet per day [2]		**(3,965)**	(430)	—
Total noncontrolling interest		**(12,394)**	(1,230)	—
Total net hydrocarbons - continuing operations excluding NCI [2,3]		**173,255**	123,107	110,892
Discontinued operations				
Net crude oil and condensate – barrels per day		**12,215**	28,676	32,986
Net natural gas liquids – barrels per day		**325**	792	829
Net natural gas – thousands of cubic feet per day [2]		**50,758**	110,223	112,974
Total discontinued operations		**21,000**	47,839	52,644
Total net hydrocarbons produced excluding NCI [2,3]		**194,255**	170,946	163,536
Estimated net hydrocarbon reserves - million equivalent barrels [3,4]		**825.0**	844.0	698.2

[1] 2019 and 2018 include net volumes attributable to a noncontrolling interest in MP GOM.
[2] Natural gas converted on an energy equivalent basis of 6:1.
[3] NCI – noncontrolling interest in MP GOM.
[4] At December 31, 2019 and 2018, includes 24.6 MMBOE and 28.4 MMBOE, respectively, relating to noncontrolling interest.

The following table contains hydrocarbons sold during the three years ended December 31, 2019.

Barrels per day unless otherwise noted		2019	2018	2017
Continuing operations				
Net crude oil and condensate				
United States	Onshore	**34,578**	31,787	34,649
	Gulf of Mexico [1]	**66,272**	17,729	11,551
Canada	Onshore	**6,329**	5,690	3,004
	Offshore	**6,722**	6,884	7,525
Other		**427**	233	150
Total net crude oil and condensate - continuing operations		**114,328**	62,323	56,879
Net natural gas liquids				
United States	Onshore	**5,731**	6,578	6,867
	Gulf of Mexico [1]	**4,894**	1,147	947
Canada	Onshore	**1,263**	1,073	508
Total net natural gas liquids - continuing operations		**11,888**	8,798	8,322
Net natural gas – thousands of cubic feet per day				
United States	Onshore	**30,692**	31,832	32,629
	Gulf of Mexico [1]	**52,068**	14,356	11,901
Canada	Onshore	**271,355**	266,416	226,218
Total net natural gas - continuing operations		**354,115**	312,604	270,748
Total net hydrocarbons - continuing operations including NCI [2,3]		**185,235**	123,222	110,326
Noncontrolling interest				
Net crude oil and condensate – barrels per day		**(11,115)**	(940)	—
Net natural gas liquids – barrels per day		**(507)**	(24)	—
Net natural gas – thousands of cubic feet per day [2]		**(3,965)**	(430)	—
Total noncontrolling interest		**(12,283)**	(1,036)	—
Total net hydrocarbons - continuing operations excluding NCI [2,3]		**172,952**	122,186	110,326
Discontinued operations				
Net crude oil and condensate – barrels per day		**12,100**	29,426	32,321
Net natural gas liquids – barrels per day		**296**	786	1,048
Net natural gas – thousands of cubic feet per day [2]		**50,758**	110,223	112,974
Total discontinued operations		**20,856**	48,583	52,198
Total net hydrocarbons sold excluding NCI [2,3]		**193,808**	170,769	162,524

[1] 2019 and 2018 include net volumes attributable to a noncontrolling interest in MP GOM.
[2] Natural gas converted on an energy equivalent basis of 6:1.
[3] NCI – noncontrolling interest in MP GOM.

2019 vs 2018

Total hydrocarbon production from continuing operations averaged 185,649 barrels of oil equivalent per day in 2019, which represented a 49% increase from the 124,337 barrels per day produced in 2018. The increase is principally due to the acquisition of producing Gulf of Mexico assets as part of the MP GOM transaction in the fourth quarter 2018 and the addition of further Gulf of Mexico assets as part of the LLOG acquisition in the second quarter of 2019.

Average crude oil and condensate production from continuing operations was 114,742 barrels per day in 2019 compared to 63,438 barrels per day in 2018. The increase of 51,304 barrels per day was principally due to higher volumes in the Gulf of Mexico (48,121 barrels per day) due to the acquisition of assets as part of the MP GOM transaction and the LLOG acquisition On a worldwide basis, the Company's crude oil and condensate prices averaged $60.27 per barrel in 2019 compared to $65.87 per barrel in 2018, a decrease of 9% year over year.

Total production of natural gas liquids (NGL) from continuing operations was 11,888 barrels per day in 2019 compared to 8,798 barrels per day in the 2018 period. The average sales price for U.S. NGL was $14.85 per barrel in 2019 compared to $26.12 per barrel in 2018. The average sales price for NGL in Canada was $26.04 per barrel in 2019 compared to $37.47 per barrel in 2018. NGL prices are higher in Canada due to the higher value of product produced at the Kaybob Duvernay and Placid Montney assets.

Natural gas sales volumes from continuing operations averaged 354 million cubic feet per day (MMCFD) in 2019 compared to 313 MMCFD in 2018. The increase of 42 MMCFD was a primarily the result of higher volumes in the Gulf of Mexico (38 MMCFD). Higher volumes in the Gulf of Mexico are due to the acquisition of assets related to the MP GOM transaction and the LLOG acquisition.

Natural gas prices for the total Company averaged $1.80 per thousand cubic feet (MCF) in 2019 , versus $1.93 per MCF average in 2018. Average prices in the U.S. and Canada in 2019 were $2.45 and $1.60 respectively.

2018 vs 2017

Total hydrocarbon production from continuing operations averaged 124,337 barrels of oil equivalent per day in 2018, which represented a 12% increase from the 110,892 barrels per day produced in 2017. The increase in crude oil production year over year was primarily due to new drilling and the acquisition of properties relating to the MP GOM transaction.

Average crude oil and condensate production from continuing operations was 63,438 barrels per day in 2018 compared to 57,445 barrels per day in 2017. The increase in crude oil production year over year was primarily due to new drilling and the acquisition of properties relating to the MP GOM transaction. On a worldwide basis, the Company's crude oil and condensate prices averaged $65.87 per barrel in 2018 compared to $51.51 per barrel in 2017, an increase of 28% year over year.

Total production of natural gas liquids (NGL) from continuing operations was 8,798 barrels per day in 2018 compared to 8,322 per day in 2017. The average sales price for U.S. NGL was $26.12 per barrel in 2018 compared to $20.85 per barrel in 2017. The average sales price of NGL in Canada was $37.47 per barrel in 2018 compared to $29.64 per barrel in 2017. NGL prices are higher in Canada due to the higher value of product produced at the Kaybob Duvernay and Placid Montney assets.

Natural gas sales volumes from continuing operations averaged 313 million cubic feet per day (MMCFD) in 2018 compared to 271 MMCFD in 2017. The increase of 42 MMCFD was attributable to an 18% increase in natural gas production in Canada, primarily in Tupper Montney and Placid Montney areas as well as an increase in natural gas production in the U.S. Gulf of Mexico.

Natural gas prices for the total Company averaged $1.93 per thousand cubic feet (MCF) in 2018, versus $2.25 per MCF average in 2017. Average prices in the U.S. and Canada in 2018 were $3.18 and $2.96 respectively.

Table of Contents

The following table contains the weighted average sales prices excluding transportation cost deduction for the three years ended December 31, 2019. Comparative periods are conformed to current presentation.

		2019	2018	2017
Weighted average Exploration and Production sales prices				
Continuing operations				
Crude oil and condensate – dollars per barrel				
United States	Onshore	**$ 59.45**	67.80	51.30
	Gulf of Mexico [1]	**61.09**	64.52	50.71
Canada [2]	Onshore	**50.29**	53.85	47.46
	Offshore	**64.91**	70.16	55.39
Other		**74.70**	71.48	—
Natural gas liquids – dollars per barrel				
United States	Onshore	**14.60**	25.68	20.40
	Gulf of Mexico [1]	**15.10**	28.27	24.13
Canada [2]	Onshore	**26.04**	37.47	29.64
Natural gas – dollars per thousand cubic feet				
United States	Onshore	**2.47**	3.11	2.92
	Gulf of Mexico [1]	**2.43**	3.35	3.10
Canada [2]	Onshore	**1.60**	1.71	2.11
Discontinued operations				
Crude oil and condensate – dollars per barrel				
Malaysia [3]	Sarawak	**70.39**	62.38	53.19
	Block K	**65.75**	65.44	52.18
Natural gas liquids – dollars per barrel				
Malaysia [3]	Sarawak	**48.23**	69.69	51.57
Natural gas – dollars per thousand cubic feet				
Malaysia [3]	Sarawak	**3.60**	3.78	3.60
	Block K	**0.24**	0.24	0.23

[1] Prices include the effect of noncontrolling interest share for MP GOM.
[2] U.S. dollar equivalent.
[3] Prices are net of payments under the terms of the respective production sharing contracts.

Cost per equivalent barrel sold for these production-related expenses are shown by geographical area in the following table.

(Dollars per equivalent barrel)	**2019**	2018	2017
Continuing operations			
United States – Eagle Ford Shale			
Lease operating expense	**$ 8.70**	8.84	7.35
Severance and ad valorem taxes	**2.82**	3.20	2.47
Depreciation, depletion and amortization (DD&A) expense	**24.19**	24.54	25.65
United States – Gulf of Mexico			
Lease operating expense	**10.89**	11.39	13.81
DD&A expense	**16.43**	16.50	20.44
Canada – Onshore			
Lease operating expense	**5.49**	4.52	4.94
Severance and ad valorem taxes	**0.07**	0.06	0.10
DD&A expense	**10.94**	10.61	9.92
Canada – Offshore			
Lease operating expense	**14.95**	15.21	9.61
DD&A expense	**13.07**	13.68	12.95
Total oil and natural gas continuing operations			
Lease operating expense	**8.95**	7.87	7.44
Severance and ad valorem taxes	**0.71**	1.16	1.08
DD&A expense	**16.98**	17.25	18.67
Total oil and natural gas continuing operations – excluding noncontrolling interest			
Lease operating expense	**8.81**	7.87	7.44
Severance and ad valorem taxes	**0.76**	1.17	1.08
DD&A expense	**17.05**	17.28	18.67
Discontinued Operations			
Malaysia			
Lease operating expense	**16.49**	11.39	8.86
DD&A expense	**4.60**	11.20	10.74

Results of Operations (Contd.)

Corporate

2019 vs 2018

Corporate activities, which include interest expense and income, foreign exchange effects, realized and unrealized gains/losses on crude oil contracts and corporate overhead not allocated to Exploration and Production, reported a net loss of $271.8 million in 2019 compared to net loss of $108.3 million in 2018. The $163.5 million unfavorable variance is due to a 2018 income tax credit ($120.0 million, related to an IRS interpretation of the Tax Act), higher interest charges ($38.6 million) primarily due to early retirement of debt, foreign exchange losses ($6.6 million; versus an $16.1 million gain in 2018), Ecuador arbitration income in 2018 ($26.0 million); partially off-set by lower losses on forward crude contracts ($41.1 million) and lower income taxes (excluding the $120 million tax act credit; $22.1 million).

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 $108.3 million in 2018 compared to a loss of $616.2 million in 2017. The $507.9 million favorable variance in 2018 was primarily due to a credit to income tax expense of $135.7 million primarily related to an IRS interpretation of the 2017 Tax Act (versus a charge in 2017 of $274.0 million), lower foreign exchange losses ($16.1 million gain in 2018 versus an $82.4 million loss in 2017), and income related to an Ecuador arbitration settlement ($26.0 million), partially offset by losses on crude contracts used to hedge price risk ($42.0 million) versus a gain in the prior period ($9.5 million), and higher G&A expense ($6.9 million). Further, the 2017 period included a deferred tax charge of $65.2 million associated with the estimated tax consequence of future repatriation of Malaysian and Canadian earnings that were deemed no longer indefinitely invested.

Discontinued Operations

The Company has presented its Malaysia E&P operations and former U.K. and U.S. refining and marketing operations as discontinued operations in its consolidated financial statements.

Malaysia E&P operations reported earnings of $1,086.6 million in 2019 compared to $251.7 million in the 2018 period. Results for 2019 were favorable by $834.9 million primarily as a result of the gain on sale of Malaysia to PTT Exploration and Production Public Company Limited (PTTEP) (see Note G). The sale closed on July 10, 2019. The Company recognized a net gain of $985.4 million on the transaction. Excluding the gain, Malaysia income was $168.2 million lower than the 2018 period principally due to lower revenues ($486.4 million), partially offset by lower operating expenses ($74.9 million), lower depreciation ($164.9 million) and lower income taxes ($73.1 million). Lower revenues are principally due to lower volumes sold as a result of a partial year of operations and declining daily production. The lower depreciation is due to the cessation of charges as a result of the assets being classified as held for sale and partial year of operations.

2018 vs 2017

Malaysia E&P operations reported earnings of $269.5 million in 2018, compared to earnings of $224.2 million in 2017. Results were favorable by $45.3 million due to higher revenues ($73.1 million), lower depreciation ($6.0 million), and lower redetermination/unitization expense ($3.7 million), partially offset by higher lease operating expenses ($33.3 million), and higher taxes ($16.9 million). Higher revenues are principally due to higher realized prices, partially offset by lower volumes sold. Lower depreciation is due to lower volumes sold. Lower other expenses are due to the cost of a rig exit recorded in 2017. Higher lease operating expenses are due to higher platform, onshore facility and sub-sea maintenance costs. The higher taxes are due to higher pre-tax profits. The redetermination/unitization charges (in both years) relates to the executed unitization agreement for the Gumusut-Kakap (GK) and Geronggong/Jagus East fields originally signed in Q4 2017.

Financial Condition

Cash Provided by Operating Activities

Net cash provided by continuing operating activities was $1,489.1 million in 2019 compared to $749.4 million in 2018. The $739.7 million improvement in cash provided by continuing operations activities in 2018 was primarily attributable to higher sales ($1,010.6 million) from higher volumes, realized gains on forward crude contracts (vs 2018 losses; $108.4 million), partially off-set by higher lease operating, transportation, gathering and processing expenses ($352.6 million). Higher revenues, lease operating, transportation, gathering and processing expenses and higher depreciation expenses are principally a result of the LLOG acquisition and a full year of the 2018 MP GOM transaction, which was completed in the fourth quarter 2018.

Cash flow provided by continuing operations was $136.0 million higher in 2018 than in 2017 due to higher realized oil and natural gas sales prices, partially offset by higher cash taxes paid as a result of repatriating cash from Canada and payments made on hedge losses.

The total reductions of operating cash flows for interest paid during the three years ended December 31, 2019, 2018, and 2017 were $179.7 million, $158.1 million, and $144.5 million, respectively. Higher cash interest paid in 2019 was due to maintaining a higher average outstanding revolver balance 2019 (timing of LLOG acquisition and Malaysia disposition) and also the cost of the $500 million term loan outstanding from May to July 2019.

Cash Used for Investing Activities

Cash used for property additions and dry holes, which includes amounts expensed, were $1,344.3 million and $1,011.3 million in 2019 and 2018, respectively. The increase is due to exploration and development capital expenditures at the Eagle Ford Shale and Gulf of Mexico in the U.S. and Kaybob Duvernay in Canada. Cash used for acquisition of oil and natural gas properties was $1,212.3 million in 2019 compared to $794.6 million in 2018. In 2019 and 2018 the Company acquired certain Gulf of Mexico assets attributable to the LLOG and MP GOM acquisitions, respectively (see business review section).

The accrual basis of capital expenditures, which includes $1,261.1 million for proved property acquisitions (principally the LLOG acquisition) in 2019 and the $794.6 million MP GOM acquisition in 2018, were as follows:

	Year Ended December 31,		
(Millions of dollars)	**2019**	2018	2017
Capital Expenditures			
Exploration and production	$ **2,683.2**	1,818.8	942.5
Corporate	**15.0**	22.7	10.3
Total capital expenditures	$ **2,698.2**	1,841.5	952.8
Total capital expenditures excluding proved property acquisitions	$ **1,437.1**	1,046.9	952.8
Total capital expenditures excluding proved property acquisitions and NCI	$ **1,402.3**	1,043.9	952.8

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

	Year Ended December 31,		
(Millions of dollars)	**2019**	2018	2017
Property additions and dry hole costs per cash flow statements	$ **1,344.3**	1,011.3	910.0
Acquisition of oil properties	**1,212.3**	794.6	—
Geophysical and other exploration expenses	**48.5**	41.1	63.3
Capital expenditure accrual changes and other	**93.1**	(5.5)	(20.5)
Total capital expenditures	$ **2,698.2**	1,841.5	952.8

Proceeds from sales of property and equipment generated cash of $20.4 million in 2019 compared to $1.2 million in 2018 primarily relating to the proceeds from the sale of certain non-core assets in the Midland basin in 2019.

Cash Used by and Provided by Financing Activities

During 2019, net cash used by financing activities was $1,130.0 million, compared to net cash provided by financing activities of $143.6 million during 2018. In 2019, the cash provided by financing activities was principally from borrowings on our revolver and short-term loan ($1,725.0 million) to fund the LLOG acquisition (see above). These borrowings, along with the opening revolver balance ($325.0 million) of $2,050.0 million were repaid in July 2019 following the completion of the

Financial Condition (Contd.)

Malaysia divestment. The Company issued $550 million notes due December 2027 that bear a rate of 5.875%, for net proceeds of $542.4 million; these proceeds were used to redeem a portion of the Company's $500 million 4.00% notes due June 2022 and a portion of the Company's $600 million 4.45% notes due December 2022 ($521.3 million in the aggregate). The Company paid an early retirement premium of $26.6 million in relation to the retirement of the debt. Finally, in 2019, the Company also used cash to buy back issued ordinary shares of $499.9 million.

During 2018, the Company borrowed $325.0 million on its revolving credit facility to partially fund the MP GOM transaction, which was fully repaid following the completion of the Malaysia divestment in 2019.

During 2017 the Company issued $550 million notes in August 2017 that bear a rate of 5.75% and mature on August 15, 2025, for net proceeds of $541.6 million; these proceeds were used to redeem the Company's $550 million 3.50% notes in September 2017. The 3.50% notes had a maturity date of December 2017 and were retired early.

Total cash dividends to shareholders amounted to $163.7 million in 2019, $173.0 million in 2018, and $172.6 million in 2017. Lower cash dividends in 2019 were the result of lower shares outstanding as a result of the share buy-back.

Working Capital

At the end of 2019, working capital (total current assets less total current liabilities - excluding assets and liabilities held for sale) amounted to a net working capital liability of $79.0 million (2018: net working capital asset of $146.3 million). The total working capital decrease in 2019 is primarily attributable to higher accounts payable ($254.1 million), higher current operating lease liabilities ($92.3 million), lower cash ($53.2 million); and partially offset by higher accounts receivable ($195.0 million). Higher accounts receivables and accounts payable are principally due to the increase in activity (both operating and capital) from the LLOG and MP GOM transactions. The higher operating lease liabilities is due to the implementation of ASC 842, Leases (see Note B).

Cash and cash equivalents as of December 31, 2019 totaled $306.8 million (2018: $359.9 million). The decrease in 2019 is a function of the business activity described above under cash provided by operating activities, cash used for investing activities and cash provided by (used by) financing activities (which includes a $499.9 million buy back of issued ordinary shares). The decrease in cash from 2017 to 2018 was primarily related to the use of cash on hand to fund the MP GOM acquisition at the end of 2018.

Cash and invested cash are maintained in several operating locations outside the United States. At December 31, 2019, Cash and cash equivalents held outside the U.S. included U.S dollar equivalents of approximately $116.5 million (2018: $223.2 million), the majority of which was held in Canada. In addition, approximately $15.2 million and $10.0 million of cash were held in the U.K. and Brunei, respectively, and have been classified as part of Assets held for sale in the Consolidated Balance Sheets at year-end 2019. In certain cases, the Company could incur cash 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 earnings repatriated to the U.S. See Note J of the consolidated financial statements for further information regarding potential tax expense that could be incurred upon distribution of foreign earnings back to the United States.

Capital Employed

At December 31, 2019, long-term debt of $2,803.4 million was $305.9 million lower than year-end 2018, principally as a result of a lower outstanding balance on the revolving credit facility (prior year balance used to partially fund the MP GOM acquisition and was repaid following the divestment of the Malaysia business in 2019). A summary of capital employed at December 31, 2019 and 2018 follows.

	December 31, 2019		December 31, 2018	
(Millions of dollars)	**Amount**	**%**	Amount	%
Capital employed				
Long-term debt	**$ 2,803.4**	**33.9%**	$ 3,109.3	39.2%
Murphy shareholders' equity	**5,467.5**	**66.1%**	4,829.3	60.8%
Total capital employed	**$ 8,270.8**	**100.0%**	$ 7,938.6	100.0%

Murphy shareholders' equity was $5.47 billion at the end of 2019 (2018: $4.83 billion; 2017: $4.62 billion). Shareholders' equity increased in 2019 and 2018 primarily due to net income earned ($1.15 billion), sale and leaseback gain recognized upon adoption of ASU 2016-02, Topic 842 ($0.11 billion); partially off-set by shares repurchased ($0.50 billion) and cash dividends paid ($0.16 billion). Murphy shareholders' equity increased in 2018 (vs 2017) primarily due to net income earned ($0.41 billion) partially off-set by cash dividends ($0.17 billion). A summary of transactions in stockholders' equity accounts is presented in the Consolidated Statements of Stockholders' Equity on page 57 of this Form 10-K report.

Financial Condition (Contd.)

Other Balance Sheet Activity

Other significant changes in Murphy's balance sheet at the end of 2019, compared to 2018 are discussed below.

As a result of the adoption of ASU 2016-02, Topic 842, right-of-use assets of $598.3 million, current lease liabilities for operating leases of approximately $92.3 million and non-current lease liabilities of $521.3 million are recorded on the balance sheet at the end of 2019.

The increase in deferred income tax liabilities of $77.3 million to $207.2 million is principally a result of the implementation of ASU 2016-02 (see Note B).

Long-term asset retirement obligations increased $73.3 million to $825.8 million, principally due to increased obligations associated with the LLOG transaction.

Property, plant and equipment, net of depreciation increased $1,537.6 million principally as a result of the LLOG acquisition, capital expenditures in the year, off-set by the depreciation charge for the year. Capital expenditures are discussed above in the 'Cash Used for Investing Activities' section.

Murphy had commitments for capital expenditures of approximately $574.5 million at December 31, 2019 (2018: $383.1 million). This amount includes $379.7 million for approved expenditure for capital projects relating to non-operated interests, principally related to development in deepwater U.S. Gulf of Mexico fields including new fields acquired as part of the MP GOM and LLOG transactions.

The primary sources of the Company's liquidity are internally generated funds, access to outside financing and working capital. The Company generally uses its internally generated funds to finance its capital and operating expenditures, but it also maintains lines of credit with banks and will borrow as necessary to meet spending requirements. At December 31, 2019, the Company has a $1.6 billion senior unsecured guaranteed credit facility (RCF) with a major banking consortium, which expires in November 2023.

At December 31, 2019, the Company had no outstanding borrowings under the RCF and $3.7 million of outstanding letters of credit, which reduce the borrowing capacity of the RCF. Borrowings under the RCF bear interest at rates, based, at the Company's option, on the "Alternate Base Rate" of interest in effect plus the "ABR Spread" or the "Adjusted LIBOR Rate," which is a periodic fixed rate based on LIBOR with a term equivalent to the interest period for such borrowing, plus the "Eurodollar Spread." The "Alternate Base Rate" of interest is the highest of (i) the Wall Street Journal prime rate, (ii) the New York Federal Reserve Bank Rate plus 0.50%, and (iii) one-month LIBOR plus 1.00%. The "Eurodollar Spread" ranges from 1.075% to 2.10% per annum based upon the Corporation's senior unsecured long-term debt securities credit ratings (the "Credit Ratings"). A facility fee accrues and is payable quarterly in arrears at a rate ranging from 0.175% to 0.40% per annum (based upon the Company's Credit Ratings) on the aggregate commitments under the 2018 facility. At December 31, 2019, the interest rate in effect on borrowings under the facility was 3.21%. At December 31, 2019, the Company was in compliance with all covenants related to the RCF.

Current financing arrangements are outlined in more detail in Note H to the consolidated financial statements.

Environmental Matters

Murphy faces various environmental risks that are inherent in exploring for, developing and producing hydrocarbons. To help manage these risks, the Company has established a robust health, safety and environmental governance program comprised of a worldwide policy, guiding principles, annual goals and a management system incorporating oversight at each business unit, senior leadership and board levels. The Company strives to minimize these risks by continually improving its processes through design, operation and implementation of a comprehensive asset integrity plan, and through emergency and oil spill response planning to address any credible risks. These plans are presented to, reviewed and approved by a health, safety and environment committee consisting of certain members of Murphy's Board of Directors.

The oil and natural gas industry is subject to numerous international, national, state, provincial and local environmental laws and regulations. Murphy allocates a portion of both its capital expenditures and its general and administrative budget to assure compliance with existing and anticipated environmental laws and regulations. These requirements affect virtually all operations of the Company and increase Murphy's overall cost of business, including its capital costs to construct, maintain and upgrade equipment and facilities as well as operating costs for ongoing compliance.

The principal environmental laws and regulations to which Murphy is subject address such matters as the generation, storage, handling, use, disposal and remediation of petroleum products, wastewater and hazardous materials, and the emission and discharge of such materials to the environment, including greenhouse gas emissions, wildlife, habitat and water protection and the placement, operation and decommissioning of production equipment. These laws and regulations also generally require

Environmental Matters (Contd.)

permits for existing operations, as well as the construction or development of new operations and the decommissioning facilities once production has ceased. Violations can give rise to sanctions including significant civil and criminal penalties, injunctions, construction bans and delays.

Environmental laws and regulations are subject to frequent change and tend to become more stringent over time. Potential changes in the federal administration create uncertainty in future policy and enforcement. Any current or future air emission requirements applicable to Murphy could curtail operations or otherwise result in operational delays, liabilities and increased costs.

Certain jurisdictions in which the Company operates could require more stringent permitting, including greater transparency, regarding chemical disclosure, water usage, disposal and well construction requirements. Regulators are also becoming increasingly focused on air emissions from the oil and natural gas industry including volatile organic compounds and methane emissions.

Murphy also could be subject to strict liability for environmental contamination in various jurisdictions where we operate including with respect to its current or former properties, operations and waste disposal sites, or those of its predecessors. Contamination has been identified at some locations and the Company has been required, and in the future may be required, to remove or remediate previously disposed wastes; or otherwise clean up contaminated soil, surface water or groundwater, address spills and leaks from pipelines and production equipment, and perform remedial plugging operations. In addition to significant investigation and remediation costs, such matters can result in fines and also give rise to third-party claims for personal injury and property or other environmental damage.

Climate Change

Murphy is currently required to report greenhouse gas emissions from its U.S. operations in the Gulf of Mexico and onshore in south Texas and in its Canadian onshore business in British Columbia and Alberta. In British Columbia and Alberta, Murphy is subject to a carbon tax on the purchase or use of many carbon-based fuels. Additionally, starting in 2017, a carbon tax began to be applied to certain operations in Alberta. Any limitation on, or further regulation of, greenhouse gases; including through a cap and trade system, technology mandate, emissions tax, or expanded reporting requirements, could restrict the Company’s operations, curtail demand for hydrocarbons generally and/or impose increased costs to operate and maintain facilities, install pollution emission controls and administer and manage emissions trading programs.

Safety Matters

The Company is subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable foreign and state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information regarding hazardous materials used or produced in Murphy’s operations be maintained and provided to employees, state and local government authorities and citizens. The Company believes that its operations are in substantial compliance with applicable safety and exposure requirements, including general industry standards, record-keeping requirements and the monitoring of occupational exposure to regulated substances.

Other Matters

Impact of inflation – General inflation was moderate during the last three years in most countries where the Company operates; however, the Company’s revenues and capital and operating costs are influenced to a larger extent by specific price changes in the oil and natural gas and allied industries than by changes in general inflation. Crude oil prices generally reflect the balance between supply and demand, with crude oil prices being particularly sensitive to OPEC production levels and/or attitudes of traders concerning supply and demand in the future. Prices for oil field goods and services are usually affected by the worldwide prices for crude oil.

The increase in oil prices in 2017 and 2018 (compared to 2015 to 2016) led to some upward inflation pressure in oil field goods and service costs during those years. In 2019 the cost of goods and services in the oil and natural gas industry were stable.

Natural gas prices are also affected by supply and demand, which are often affected by the weather and by the fact that delivery of natural gas is generally restricted to specific geographic areas.

As a result of the overall volatility of oil and natural gas prices, it is not possible to predict the Company’s future cost of oil field goods and services.

Accounting changes and recent accounting pronouncements – see Note B

Other Matters (Contd.)

Significant accounting policies – In preparing the Company's consolidated financial statements in accordance with U.S. GAAP, management must make a number of estimates and assumptions related to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Application of certain of the Company's accounting policies requires significant estimates. The most significant of these accounting policies and estimates are described below.

Oil and natural gas proved reserves – Oil and natural gas proved reserves are defined by the SEC as those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations before the time at which contracts providing the right to operate expire (unless evidence indicates that renewal is reasonably certain). Proved developed reserves of oil and natural gas can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well, or through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Although the Company's engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. SEC rules require the Company to use an unweighted average of the oil and natural gas prices in effect at the beginning of each month of the year for determining quantities of proved reserves. These historical prices often do not approximate the average price that the Company expects to receive for its oil and natural gas production in the future. The Company often uses significantly different oil and natural gas price and reserve assumptions when making its own internal economic property evaluations. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserves quantities.

Estimated reserves are subject to future revision, certain of which could be substantial, based on the availability of additional information, including reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Reserves revisions inherently lead to adjustments of the Company's depreciation rates and the timing of settlement of asset retirement obligations. Downward reserves revisions can also lead to significant impairment expense. The Company cannot predict the type of oil and natural gas reserves revisions that will be required in future periods.

The Company's proved reserves of crude oil, natural gas liquids and natural gas are presented on pages 94 to 102 of this Form 10-K report. Murphy's estimations for proved reserves were generated through the integration of available geoscience, engineering, and economic data, and commercially available technologies, to establish 'reasonable certainty' of economic producibility. As defined by the SEC, reasonable certainty of proved reserves describes a high degree of confidence that the quantities will be recovered. In estimating proved reserves, Murphy uses familiar industry-accepted methods for subsurface evaluations, including performance, volumetric, and analog-based studies.

Where appropriate, Murphy includes reliable geologic and engineering technology to estimate proved reserves. Reliable geologic and engineering technology is a method or combination of methods that are field-tested and have demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. This integrated approach increases the quality of and confidence in Murphy's proved reserves estimates. It was utilized in certain undrilled acreage at distances greater than the directly offsetting development spacing areas, and in certain reservoirs developed with the application of improved recovery techniques. Murphy utilized a combination of 3D seismic interpretation, core analysis, wellbore log measurements, well test data, historic production and pressure data, and commercially available seismic processing and numerical reservoir simulation programs. Reservoir parameters from analogous reservoirs were used to strengthen the reserves estimates when available.

See further discussion of proved reserves and changes in proved reserves during the three years ended December 31, 2019 beginning on pages 5 and 94 of this Form 10-K report.

Property, Plant & Equipment - impairment of long-lived assets – The Company continually monitors its long-lived assets recorded in Property, plant and equipment (PPE) in the Consolidated Balance Sheet to make sure that they are fairly presented. The Company must evaluate its PPE for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable from future cash flows.

A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the amount of oil and natural gas that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, future capital, operating and abandonment costs, and future inflation levels.

Other Matters (Contd.)

Significant accounting policies (contd.)

The need to test a long-lived asset for impairment can be based on several factors, including but not limited to a significant reduction in sales prices for oil and/or natural gas, unfavorable revisions of oil or natural gas reserves, or other changes to contracts, environmental regulations, tax laws or other regulatory changes. All of these factors must be considered when evaluating a property's carrying value for possible impairment.

Due to the volatility of world oil and natural gas markets, the actual sales prices for oil and natural gas have often been different from the Company's projections.

Estimates of future oil and natural gas production and sales volumes are based on a combination of proved and risked probable and possible reserves. Although the estimation of reserves and future production is uncertain, the Company believes that its estimates are reasonable; however, there have been cases where actual production volumes were higher or lower than projected and the timing was different than the original projection. The Company adjusts reserves and production estimates as new information becomes available.

The Company generally projects future costs by using historical costs adjusted for both assumed long-term inflation rates and known or expected changes in future operations. Although the projected future costs are considered to be reasonable, at times, costs have been higher or lower than originally estimated.

The company did not record any impairment expense in 2019 or 2017.

In 2018, the Company recorded an impairment expense of $20.0 million to reduce the carrying value of select Midland properties to its net recoverable value.

Property, Plant & Equipment – business combinations – The Company may acquire assets and assume liabilities in transactions accounted for as business combinations, such as the LLOG acquisition in 2019 and the MP GOM transaction with PAI in 2018. In connection with a business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed, based on fair values as of the acquisition date. Any excess of the purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

Significant assumptions are involved in determining the fair value of assets acquired and liabilities assumed, such as the fair values assigned to proved and unproved crude oil and natural gas properties. In most cases, sufficient market data is not available regarding the fair values of proved and unproved properties, and the Company prepares estimates of such properties based on the fair value of associated crude oil, natural gas and NGL reserves. The primary assumptions used to arrive at estimates of future net cash flows are reserves quantities, commodity prices, and capital and operating costs. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Beginning in the fourth quarter of 2018, Murphy reports 100% of the sales volumes, revenues, costs, assets and liabilities including the 20% noncontrolling interest (NCI), of the new Gulf of Mexico transaction (MP GOM) with Petrobras Americas Inc (PAI), in accordance with accounting for noncontrolling interest as prescribed by ASC 810-10-45.

Accounting for retirement and postretirement benefit plans – Murphy and certain of its subsidiaries maintain defined benefit retirement plans covering certain full-time employees. The Company also sponsors health care and life insurance benefit plans covering most retired U.S. employees. The expense associated with these plans is estimated by management based on a number of assumptions and with consultation assistance from qualified third-party actuaries. The most important of these assumptions for the retirement plans involve the discount rate used to measure future plan obligations and the expected long-term rate of return on plan assets. For the retiree medical and insurance plans, the most important assumptions are the discount rate for future plan obligations and the health care cost trend rate. Discount rates are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Anticipated health care cost

Other Matters (Contd.)

Significant accounting policies (contd.)

trend rates are determined based on prior experience of the Company and an assessment of near-term and long-term trends for medical and drug costs.

Based on bond yields at December 31, 2019, the Company has used a weighted average discount rate of 3.35% at year-end 2019 for the primary U.S. plans. This weighted average discount rate is 1.0% lower than prior year, which increased the Company's recorded liabilities for retirement plans compared to a year ago. Although the Company presently assumes a return on plan assets of 6.0% for the primary U.S. plan, it periodically reconsiders the appropriateness of this and other key assumptions. The Company's retirement and postretirement plan expenses in 2020 are expected to be $1.8 million higher than 2019 primarily due to increased amortization of the interest cost component. Cash contributions are anticipated to be $8.2 million higher in 2020.

In 2019, the Company paid $25.9 million into various retirement plans and $2.3 million into postretirement plans. In 2020, the Company is expecting to fund payments of approximately $31.2 million into various retirement plans and $5.2 million for postretirement plans. The Company could be required to make additional and more significant funding payments to retirement plans in future years. Future required payments and the amount of liabilities recorded on the balance sheet associated with the plans could be unfavorably affected if the discount rate declines, the actual return on plan assets falls below the assumed return, or the health care cost trend rate increase is higher than expected.

As described above, the Company's retirement and postretirement expenses are sensitive to certain assumptions, primarily related to discount rates and assumed return on plan assets. A 0.5% decline in the discount rate would increase 2020 annual retirement expenses by $1.8 million and decrease postretirement expenses by $0.1 million; and a 0.5% decline in the assumed rate of return on plan assets would increase 2020 retirement expense by $2.7 million.

Contractual obligations and guarantees – The Company is obligated to make future cash payments under borrowing arrangements, operating leases, purchase obligations primarily associated with existing capital expenditure plans, and other long-term liabilities. Total payments due after 2019 under such contractual obligations and arrangements are shown in the table below.

	Amount of Obligations				
(Millions of dollars)	Total	2020	2021 - 2022	2023 - 2024	After 2024
Debt, excluding interest	$ **2,828.7**	—	578.7	550.0	1,700.0
Operating leases and other leases [1]	**865.3**	125.3	133.9	107.8	498.4
Capital expenditures, drilling rigs and other [2]	**2,435.9**	704.1	315.5	289.5	1,126.8
Other long-term liabilities, including debt interest [3]	**2,736.6**	277.5	353.3	299.4	1,806.4
Total	$ **8,866.5**	1,106.9	1,381.4	1,246.6	5,131.6

[1] Other leases refers to a finance lease in Brunei, which is classified as held for sale as of December 31, 2019 (see Note E).
[2] Capital expenditures, drilling rigs and other includes $379.7 million in 2020 for approved capital projects in non-operated interests in U.S. onshore and the Gulf of Mexico. Also includes $35.6 million (2020), $102.7 million (2021-2022), $85.5 million (2023-2024) and $285.0 million (After 2024) for pipeline transportation commitments in Canada. Also includes $40.8 million (2020), $106.3 million (2021-2022), $116.4 million (2023-2024) and $706.6 million (After 2024) for long term take or pay commitments relating to gas processing in Canada.
[3] Other long-term liabilities, including debt interest includes future cash outflows for asset retirement obligations.

The Company has entered into agreements to lease production facilities for various producing oil fields. In addition, the Company has other arrangements that call for future payments as described in the following section. The Company's share of the contractual obligations under these leases and other arrangements has been included in the table above.

In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide letters of credit that may be drawn upon if the Company fails to perform under those contracts. Total outstanding letters of credit were $172.5 million as of December 31, 2019.

Material off-balance sheet arrangements – The U.S. transportation contracts require minimum monthly payments through 2044, while Western Canada processing contracts call for minimum monthly payments through 2035. Future required minimum annual payments under these arrangements are included in the contractual obligation table above.

Outlook

Prices for the Company's primary products are often quite volatile. The price of crude oil is primarily affected by the levels of supply and demand for energy. Anticipated future variances between the predicted demand for crude oil and the projected available supply can lead to significant movement in the price of crude oil. As of February 25, 2020 closing, the NYMEX WTI forward curve price for April through December 2020 was $50. The Company continually monitors the prices for its main products and often alters its operations and spending plans based on these prices.

The Company's capital expenditure budget for 2020 is expected to be between $1.4 billion and $1.5 billion (excluding noncontrolling interest of $62.0 million). Capital and other expenditures will be routinely reviewed during 2020 and planned capital expenditures may be adjusted to reflect differences between budgeted and actual cash flow during the year. Capital expenditures may also be affected by asset purchases or sales, which often are not anticipated at the time a budget is prepared. The Company will primarily fund its capital program in 2020 using operating cash flow and available cash, 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 borrowings might be required during the year to maintain funding of the Company's ongoing development projects.

The Company currently expects average daily production in 2020 to be between 204,200 and 216,200 barrels of oil equivalent per day (including noncontrolling interest of 14,200 BOEPD).

The Company has entered into natural gas forward delivery contracts to manage risk associated with certain Canadian natural gas sales prices as follows:

Area	Commodity	Type	Volumes (Bbl/d)	Price (USD/Bbl)	Remaining Period Start Date	Remaining Period End Date
United States	WTI [1]	Fixed price derivative swap	45,000	$56.42	1/1/2020	12/31/2020

Area	Commodity	Type	Volumes (MMcf/d)	Price (CAD/Mcf)	Remaining Period Start Date	Remaining Period End Date
Montney	Natural Gas	Fixed price forward sales at AECO	97	C$2.71	1/1/2020	3/31/2020
Montney	Natural Gas	Fixed price forward sales at AECO	59	C$2.81	4/1/2020	12/31/2020

[1] West Texas Intermediate

Forward-Looking Statements

This Form 10-K 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 these 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 Item 1A. Risk Factors, which begins on page 11 of this Annual Report on Form 10-K. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

Item 7A. 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 M, 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 December 31, 2019, covering certain future U.S. crude oil sales volumes in 2020. A 10% increase in the respective benchmark price of these commodities would have increased the net payable associated with these derivative contracts by approximately $96.0 million, while a 10% decrease would have decreased the recorded payable by a similar amount, resulting in a receivable.

There were no derivative foreign exchange contracts in place at December 31, 2019.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages 48 through 111 of this Form 10-K report.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

Item 9A. CONTROLS AND PROCEDURES

Under the direction of its principal executive officer and principal financial officer, controls and procedures have been established by Murphy 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 their evaluation, with the participation of the Company’s management, as of December 31, 2019, 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) were 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.

Murphy’s management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Management has conducted an evaluation of the effectiveness of the Company’s internal control over financial reporting based on the criteria set forth in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, management concluded that the Company’s internal control over financial reporting was effective as of December 31, 2019. Under guidelines established by the SEC, companies are permitted to exclude acquisitions from their assessment of internal controls over financial reporting during the first year of an acquisition while integrating the acquired business. See Management’s report on page 48. KPMG LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of the Company’s internal control over financial reporting as of December 31, 2019 and their report is included on page 52 of this Form 10-K report.

Other than noted above, there were no changes in the Company’s internal controls over financial reporting that occurred during the fourth quarter of 2019 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Item 9B. OTHER INFORMATION

None

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Certain information regarding executive officers of the Company is included on page 19 of this Form 10-K report. Other information required by this item is incorporated by reference to the Registrant’s definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2020 under the captions “Election of Directors” and “Committees.”

Murphy Oil has adopted a Code of Ethical Conduct, which can be found under the Corporate Governance and Responsibility tab at www.murphyoilcorp.com. Stockholders may also obtain, free of charge, a copy of the Code of Ethical Conduct for Executive Management by writing to the Company’s Secretary at P.O. Box 7000, El Dorado, AR 71731-7000. Any future amendments to or waivers of the Company’s Code of Ethical Conduct for Executive Management will be posted on the Company’s Website.

Item 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to Murphy’s definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2020 under the captions “Compensation Discussion and Analysis” and “Compensation of Directors” and in various compensation schedules.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item is incorporated by reference to Murphy’s definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2020 under the captions “Security Ownership of Certain Beneficial Owners,” “Security Ownership of Management,” and “Equity Compensation Plan Information.”

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to Murphy’s definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2020 under the caption “Election of Directors.”

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by this item is incorporated by reference to Murphy’s definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2020 under the caption “Audit Committee Report.”

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements – The consolidated financial statements of Murphy Oil Corporation and consolidated subsidiaries are located or begin on the pages of this Form 10-K report as indicated below.

2. Financial Statement Schedules

All other financial statement schedules are omitted because either they are not applicable or the required information is included in the consolidated financial statements or notes thereto.

3. Exhibits – The following is an index of exhibits that are hereby filed as indicated by asterisk (*), that are considered furnished rather than filed, or that are incorporated by reference. Exhibits other than those listed have been omitted since they either are not required or are not applicable.

Exhibit No.		Incorporated by Reference to the Indicated Filing by Murphy Oil Corporation
2.1	Purchase and sale agreement dated as of April 19, 2019 between LLOG Bluewater Holdings, LLC and LLOG Exploration Offshore, LLC, as seller, and Murphy Exploration & Production Company – USA, as purchaser.	Exhibit 2.1 to Form 8-K filed June 5, 2019
2.2	First Amendment to Purchase and Sale Agreement dated as of May 31, 2019 among Murphy Exploration & Production Company - USA, LLOG Exploration Offshore, L.L.C. and LLOG Bluewater Holdings, L.L.C.	Exhibit 2.2 to Form 8-K filed June 5, 2019
2.3	Contribution Agreement dated as of October 10, 2018 among Murphy Exploration & Production Company – USA, Petrobras America Inc. and MP Gulf of Mexico, LLC	Exhibit 2.1 to Form 10-K for the year ended December 31, 2018
2.4	Share Sale and Purchase Agreement between Canam Offshore Limited and PTTEP HK Offshore Limited for the sale and purchase of the entire issued share capital of Murphy Sarawak Oil Co., Ltd. and Murphy Sabah Oil Co., Ltd., dated March 21, 2019	Exhibit 10.3 to Form 10-Q filed May 2, 2019
3.1	Certificate of Incorporation of Murphy Oil Corporation, as amended effective May 11, 2005	Exhibit 3.1 to Form 10-K for the year ended December 31, 2010
3.2	By-Laws of Murphy Oil Corporation, as amended effective February 3, 2016	Exhibit 3.2 to Form 8-K filed February 5, 2016
4.1	Indenture dated as of May 4, 1999 between Murphy Oil Corporation and SunTrust Bank, Nashville, N.A., as trustee	Exhibit 4.2 to Form 10-K for the year ended December 31, 2004
4.2	Supplemental Indenture dated as of May 4, 1999 between Murphy Oil Corporation and SunTrust Bank, Nashville, N.A., as trustee, relating to 7.05% Notes due 2029	Exhibit 4.2 to Form 10-K for the year ended December 31, 2004

4.3	Indenture dated as of May 18, 2012 between Murphy Oil Corporation and U.S. Bank National Association, as trustee	Exhibit 4.1 to Form 8-K filed May 18, 2012
4.4	First Supplemental Indenture dated as of May 18, 2012, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 4.00% Notes due 2022	Exhibit 4.2 to Form 8-K filed May 18, 2012
4.5	Second Supplemental Indenture dated as of November 30, 2012, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 3.70% Notes due 2022 and 5.125% notes due 2042	Exhibit 4.1 to Form 8-K filed November 30, 2012
4.6	Third Supplemental Indenture dated as of August 17, 2016, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 6.875% Notes due 2024	Exhibit 4.1 to Form 8-K filed August 17, 2016
4.7	Fourth Supplemental Indenture dated as of August 18, 2017, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 5.75% Notes due 2025	Exhibit 4.1 to Form 8-K filed August 18, 2017
4.8	Fifth Supplemental Indenture dated as of November 27, 2019, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, and Wells Fargo Bank, National Association, as series trustee, relating to 5.875% Notes due 2027	Exhibit 4.2 to Form 8-K filed November 27, 2019
*4.9	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934	
10.1	Credit Agreement dated as of August 10, 2016 among Murphy Oil Corporation, Murphy Exploration & Production Company – International, and Murphy Oil Company Ltd., as borrowers, JPMorgan Chase Bank, N.A., as administrative agent and the lenders party thereto	Exhibit 10.1 to Form 8-K filed August 12, 2016
10.2	Third Amendment dated as of November 17, 2017 to Credit Agreement dated as of August 10, 2016 among Murphy Oil Corporation, Murphy Exploration & Production Company – International and Murphy Oil Company Ltd., as borrowers, JPMorgan Chase Bank, N.A., as administrative agent and the lenders party thereto	Exhibit 10.1 to Form 8-K filed November 20, 2017
10.3	Fourth Amendment dated as of October 10, 2018 to Credit Agreement dated as of August 10, 2016 among Murphy Oil Corporation, Murphy Exploration & Production Company – International and Murphy Oil Company Ltd., as borrowers, JPMorgan Chase Bank, N.A., as administrative agent and the lenders party thereto	Exhibit 10.1 to Form 8-K filed October 11, 2018
10.4	Credit Agreement dated as of November 28, 2018 among Murphy Oil Corporation, Murphy Exploration & Production Company – International, and Murphy Oil Company Ltd., as borrowers, JPMorgan Chase Bank, N.A., as administrative agent and the lenders party thereto	Exhibit 10.4 to Form 10-K for the year ended December 31, 2018
10.5	2007 Long-Term Incentive Plan	Exhibit 10.1 of Murphy's Form 8-K report filed April 24, 2007
10.6	Form of employee stock option (2007 Long-Term Plan)	Exhibits 99.1 and 99.2 of Murphy's Form 10-Q report filed August 6, 2012
10.7	Murphy Oil Corporation 2012 Long-Term Incentive Plan	Exhibit A to definitive proxy statement filed March 29, 2012
*10.8	Amendment to the Murphy Oil Corporation 2012 Long-Term Incentive Plan	
10.9	Form of employee stock option (2012 Long-Term Plan)	Exhibit 99.1 to Form 10-K for the year ended December 31, 2013
10.10	Form of employee performance-based restricted stock unit grant agreement (2012 Long-Term Plan)	Exhibit 99.2 to Form 10-K for the year ended December 31, 2014
10.11	Form of stock appreciation right (2012 Long-Term Plan)	Exhibit 99.3 to Form 10-Q filed May 7, 2014
10.12	Form of employee time-based restricted stock unit grant agreement (2012 Long-Term Plan)	Exhibit 99.1 to Form 10-Q filed May 7, 2014
10.13	Form of employee time-based restricted stock unit-cash grant agreement (2012 Long-Term Plan)	Exhibit 99.2 to Form 10-Q filed May 7, 2014
10.14	Murphy Oil Corporation 2018 Long-Term Incentive Plan	Exhibit B to definitive proxy statement filed March 23, 2018
*10.15	Amendment to the Murphy Oil Corporation 2018 Long-Term Incentive Plan	

10.16	Form of employee performance-based restricted stock unit – stock settled grant agreement (2018 Long-Term Plan)	Exhibit 10.14 to Form 10-K for the year ended December 31, 2018
*10.17	Form of employee performance-based restricted stock unit – stock settled grant agreement (2018 Long-Term Plan)	
10.18	Form of employee time-based restricted stock unit – stock settled 3-year grant agreement (2018 Long-Term Plan)	Exhibit 10.15 to Form 10-K for the year ended December 31, 2018
10.19	Form of employee time-based restricted stock unit – stock settled 5-year grant agreement (2018 Long-Term Plan)	Exhibit 10.16 to Form 10-K for the year ended December 31, 2018
10.20	Murphy Oil Corporation 2013 Stock Plan for Non-Employee Directors	Exhibit A to definitive proxy statement filed March 22, 2013
10.21	Form of non-employee director restricted stock unit award (2013 NED Plan)	Exhibit 99.2 to Form 10-Q filed November 6, 2013
10.22	Murphy Oil Corporation 2018 Stock Plan for Non-Employee Directors	Exhibit A to definitive proxy statement filed March 23, 2018
10.23	First Amendment to the 2018 Stock Plan for Non-Employee Directors	Exhibit 10.1 to Form 8-K filed April 25, 2018
*10.24	Second Amendment to the 2018 Stock Plan for Non-Employee Directors	
10.25	Form of non-employee director restricted stock unit award – stock settled grant agreement (2018 NED Plan)	Exhibit 10.20 to Form 10-K for the year ended December 31, 2018
*10.26	Form of non-employee director restricted stock unit award – stock settled grant agreement (2018 NED Plan)	
10.27	Murphy Oil Corporation Non-Qualified Deferred Compensation Plan for Non-Employee Directors	Exhibit 10.6 to Form 10-K for the year ended December 31, 2015
10.28	Tax Matters Agreement dated as of August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.1 to Form 8-K filed September 5, 2013
10.29	Employee Matters Agreement dated as of August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.3 to Form 8-K filed September 5, 2013
10.30	Trademark License Agreement dated as of August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.4 to Form 8-K filed September 5, 2013
*21.1	Subsidiaries of Murphy Oil Corporation	
*23.1	Consent of Independent Registered Public Accounting Firm	
*23.2	Consent of Ryder Scott Company, L.P.	
*23.3	Consent of McDaniel & Associates Consultants Ltd.	
*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	
*32.1	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	
*99.1	Ryder Scott reserves audit report for Eagle Ford Shale and Gulf of Mexico	
*99.2	Ryder Scott reserves audit report for MP GOM JV	
*99.3	McDaniel independent audit report for Canada Onshore and Offshore proved crude oil and natural gas reserves	
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	

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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

By	/s/ ROGER W. JENKINS	Date:	February 26, 2020
	Roger W. Jenkins, President		

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 26, 2020 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ CLAIBORNE P. DEMING	/s/ R. MADISON MURPHY
Claiborne P. Deming, Chairman and Director	R. Madison Murphy, Director
/s/ ROGER W. JENKINS	/s/ WALENTIN MIROSH
Roger W. Jenkins, President and Chief Executive Officer and Director (Principal Executive Officer)	Walentin Mirosh, Director
/s/ T. JAY COLLINS	/s/ JEFFREY W. NOLAN
T. Jay Collins, Director	Jeffrey W. Nolan, Director
/s/ STEVEN A. COSSE	/s/ ROBERT N. RYAN, JR.
Steven A. Cossé, Director	Robert N. Ryan, Jr., Director
/s/ LAWRENCE R. DICKERSON	/s/ NEAL E. SCHMALE
Lawrence R. Dickerson, Director	Neal E. Schmale, Director
/s/ ELISABETH W. KELLER	/s/ LAURA A. SUGG
Elisabeth W. Keller, Director	Laura A. Sugg, Director
/s/ JAMES V. KELLEY	/s/ DAVID R. LOONEY
James V. Kelley, Director	David R. Looney, Executive Vice President and Chief Financial Officer (Principal Financial Officer)
	/s/ CHRISTOPHER D. HULSE
	Christopher D. Hulse Vice President and Controller (Principal Accounting Officer)

REPORT OF MANAGEMENT – CONSOLIDATED FINANCIAL STATEMENTS

The management of Murphy Oil Corporation is responsible for the preparation and integrity of the accompanying consolidated financial statements and other financial data. The financial statements were prepared in conformity with U.S. generally accepted accounting principles (GAAP) appropriate in the circumstances and include some amounts based on informed estimates and judgments, with consideration given to materiality.

An independent registered public accounting firm, KPMG LLP, has audited the Company's consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board and provides an objective, independent opinion about the Company's consolidated financial statements. The Audit Committee of the Board of Directors appoints the independent registered public accounting firm; ratification of the appointment is solicited annually from the shareholders. KPMG LLP's opinion covering the Company's consolidated financial statements can be found on page 49.

The Board of Directors appoints an Audit Committee annually to implement and to support the Board's oversight function of the Company's financial reporting, accounting policies, internal controls and independent registered public accounting firm. This Committee is composed solely of directors who are not employees of the Company. The Committee meets routinely with representatives of management, the Company's audit staff and the independent registered public accounting firm to review and discuss the adequacy and effectiveness of the Company's internal controls, the quality and clarity of its financial reporting, the scope and results of independent and internal audits, and to fulfill other responsibilities included in the Committee's Charter. The independent registered public accounting firm and the Company's audit staff have unrestricted access to the Committee, without management presence, to discuss audit findings and other financial matters.

REPORT OF MANAGEMENT – INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). The Company's internal controls have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements in accordance with U.S. GAAP. All internal control systems have inherent limitations, and therefore, can provide only reasonable assurance with respect to the reliability of financial reporting and preparation of consolidated financial statements.

Management has conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the criteria set forth in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the results of this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2019.

KPMG LLP has performed an audit of the Company's internal control over financial reporting and their opinion thereon can be found on page 52.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors
Murphy Oil Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Murphy Oil Corporation and subsidiaries (the Company) as of December 31, 2019 and 2018, the related consolidated statements of operations, comprehensive income (loss), cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2019, and the related notes and financial statement Schedule II (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 26, 2020 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note B to the consolidated financial statements, the Company has changed its method of accounting for leases as of January 1, 2019 due to the adoption of Accounting Standards Update No. 2016-02, *Leases.*

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Acquisition of LLOG Gulf of Mexico assets - valuation of acquired oil and gas properties

As discussed in Note D to the consolidated financial statements, the Company completed the acquisition of certain oil and gas properties from LLOG Exploration Offshore, L.L.C. and LLOG Bluewater Holdings, L.L.C. ("LLOG") for consideration of approximately $1.3 billion. The Company accounted for this transaction under the acquisition method of accounting for business combinations, which resulted in approximately $1.3 billion of assets being recorded at their estimated fair value. The Company estimated the fair value of the acquired oil and gas properties using the income approach, which required the Company to make significant estimates and assumptions related to future cash flows, the selection of the discount rates by property type and the volume of oil and gas reserves acquired. These estimates depend upon a number of factors and assumptions, and consequently, different petroleum reserve engineers could arrive at different estimates of oil and gas reserves and future net cash flows based on the same available data and using industry accepted engineering practices and scientific methods.

We identified the evaluation of the estimated fair value of the oil and gas properties acquired in the LLOG transaction as a critical audit matter. There is a high degree of subjectivity in performing procedures due to the uncertainty associated with future commodity prices, estimated future production, the expertise of professional petroleum reserve engineers required to estimate oil and gas reserves, the applied discount rates, and the judgment inherent in forecasting capital and operating costs utilized by the Company in their assessment.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company’s process to estimate the fair value of the acquired oil and gas properties, including controls over the estimation of oil and gas reserves, forecasts of future cash flows, selection of the discount rates, and the assessment of the competence, capabilities and objectivity of the internal petroleum reserve engineers. We compared the forecasted prices of oil and gas to publicly available prices. We compared the forecasted production quantities from proved oil and gas reserves to current year production results. We compared the forecasted operating costs to historical results. We assessed the forecasted nature and timing of future development costs by obtaining an understanding of the development projects and comparing the development projects with the available development plans. We evaluated the competence, capabilities, and objectivity of the internal petroleum reserve engineers. In addition, we read and considered the report of the Company’s third-party petroleum reserve specialists in connection with our evaluation of the Company’s estimated oil and gas reserves. We involved a valuation professional with specialized skills and knowledge, who assisted in:

- Evaluating the income approach that was used by the Company to estimate the fair value of the oil and gas assets; and
- Evaluating the Company’s discount rates by comparing them against discount rate ranges that were independently developed using publicly available market data for comparable entities.

Assessment of estimated oil and gas reserves on the depletion expense for proved oil and gas properties

As discussed in Note A to the consolidated financial statements, the Company calculates depletion expense related to producing oil and gas properties using the units-of-production method based on estimated proved oil and gas reserves. Under this method, costs to acquire interests in oil and gas properties and costs for the drilling and completion efforts for exploratory wells that find proved reserves and for development wells are capitalized. Capitalized costs of producing oil and gas properties, along with equipment and facilities that support production, are amortized to expense based on the units-of-production method. The Company’s internal petroleum reserve engineers estimate proved oil and gas reserves and the Company engages third-party petroleum reserve specialists to perform an independent assessment in accordance with industry and regulatory standards. For the year ended December 31, 2019, the Company recorded depreciation, depletion, and amortization expense of $1.1 billion.

We identified the assessment of the estimated proved oil and gas reserves on depletion expense for producing oil and gas properties as a critical audit matter. Complex auditor judgment was required in evaluating the Company’s process to estimate proved oil and gas reserves, which is an input to the calculation of depletion expense. Estimating proved oil and gas reserves required the expertise of professional petroleum reserve engineers. Their estimates were based on their forecasted oil and gas production, which were based on forecasted operating costs, future development costs and oil and gas prices.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company’s depletion calculation process, including controls over the estimation of proved oil and gas reserves. We evaluated the competence and objectivity of the internal petroleum reserve engineers and the third-party petroleum reserve specialists engaged by the Company. We analyzed and assessed the calculation of depletion expense for compliance with industry and regulatory standards. We compared the forecasted production assumptions used by the Company to historical production rates. We compared the forecasted operating costs to historical results. We also evaluated the forecasted nature and timing of future development costs by obtaining an understanding of the development projects and comparing the development projects with the available development plans. We assessed the oil and gas prices utilized by the internal petroleum reserve engineers by comparing them to publicly available prices and recalculated the relevant market differentials. In addition, we read and considered the report of the Company’s third-party petroleum reserve specialists in connection with our evaluation of the Company’s proved oil and gas reserve estimates.

Assessment of recoverability of property, plant, and equipment related to oil and gas properties

As described in Note A to the consolidated financial statements the Company reviews their oil and gas properties for triggering events that would indicate potential impairment. The Company analyzes indicators for possible triggers of impairment such as a significant reduction in sales prices for oil or natural gas, unfavorable revisions of oil or natural gas reserves, changes to contracts, environmental regulations, tax law or other regulatory changes. If a triggering event is identified in relation to one or more properties, an undiscounted cash flow analysis is required to quantitatively evaluate recoverability. The Company compares estimated future net cash flows expected in connection with the property to the carrying amount of the property to determine if the carrying amount is recoverable or if further quantitative analysis is required.

We identified the assessment of recoverability of property, plant, and equipment related to oil and gas properties as a critical audit matter. There is a high degree of subjectivity in performing procedures due to (1) the uncertainty associated with future commodity prices and estimated future production, (2) risk adjustment factors associated with reserve volumes, and (3) the judgment inherent in forecasting capital and operating costs used in the Company's assessment.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's property, plant, and equipment process for oil and gas properties including controls over the Company's impairment assessment process and oil and gas reserve estimation process. We compared future commodity price assumptions to publicly available market information. We assessed the competence, capabilities, and objectivity of the Company's internal petroleum reserve engineers, who estimated the oil and gas reserves, and the third-party petroleum reserve specialists engaged by the Company to evaluate the estimated proved oil and gas reserves. We evaluated the Company's cash flow analysis related to forecasted production, capital, and operating costs by comparing to historical results. We evaluated risk adjustment factors associated with reserve volumes by comparing to guideline ranges by reserve class in published industry surveys.

/s/ KPMG LLP

We have served as the Company's auditor since 1952.

Houston, Texas
February 26, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors
Murphy Oil Corporation:

Opinion on Internal Control Over Financial Reporting

We have audited Murphy Oil Corporation and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2019 and 2018, the related consolidated statements of operations, comprehensive income (loss), cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2019, and the related notes and financial statement Schedule II (collectively, the consolidated financial statements), and our report dated February 26, 2020 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Report of Management - Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

Houston, Texas
February 26, 2020

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31 (Thousands of dollars except share amounts)		2019	2018 [1]
ASSETS			
Current assets			
Cash and cash equivalents		$ **306,760**	359,923
Accounts receivable, less allowance for doubtful accounts of $1,605 in 2019 and 2018		**426,684**	231,686
Inventories	Note F	**76,123**	80,024
Prepaid expenses		**40,896**	34,316
Assets held for sale	Note E	**123,864**	173,865
Total current assets		**974,327**	879,814
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $9,333,646 in 2019 and $8,070,487 in 2018	Note G	**9,969,743**	8,432,133
Operating lease assets	Note V	**598,293**	—
Deferred income taxes	Note J	**129,287**	146,197
Deferred charges and other assets		**46,854**	49,435
Non-current assets held for sale	Note E	**—**	1,545,008
Total assets		$ **11,718,504**	11,052,587
LIABILITIES AND EQUITY			
Current liabilities			
Current maturities of long-term debt		$ **—**	668
Accounts payable		**602,096**	348,026
Income taxes payable		**19,049**	15,309
Other taxes payable		**18,613**	17,649
Operating lease liabilities		**92,286**	—
Other accrued liabilities		**197,447**	177,948
Liabilities associated with assets held for sale	Note E	**13,298**	286,458
Total current liabilities		**942,789**	846,058
Long-term debt, including capital lease obligation	Note H	**2,803,381**	3,109,318
Asset retirement obligations	Note I	**825,794**	752,519
Deferred credits and other liabilities		**613,407**	624,436
Non-current operating lease liabilities	Note V	**521,324**	—
Deferred income taxes	Note J	**207,198**	129,894
Non-current liabilities associated with assets held for sale	Note E	**—**	392,720
Total liabilities		**5,913,893**	5,854,945
Equity			
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued		**—**	—
Common Stock, par $1.00, authorized 450,000,000 shares, issued 195,089,269 shares in 2019 and 195,076,924 shares in 2018		**195,089**	195,077
Capital in excess of par value		**949,445**	979,642
Retained earnings		**6,614,304**	5,513,529
Accumulated other comprehensive loss	Note P	**(574,161)**	(609,787)
Treasury stock		**(1,717,217)**	(1,249,162)
Murphy Shareholders' Equity		**5,467,460**	4,829,299
Noncontrolling interest		**337,151**	368,343
Total equity		**5,804,611**	5,197,642
Total liabilities and equity		$ **11,718,504**	11,052,587

[1] Reclassified to conform with current presentation (see Note E). See Notes to Consolidated Financial Statements, page 58.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

Years Ended December 31 (Thousands of dollars except per share amounts)	2019	2018 [1]	2017 [1]
Revenues and other income			
Revenue from sales to customers	$ 2,817,111	1,806,473	1,300,464
(Loss) gain on crude contracts	(856)	(41,975)	9,566
Gain on sale of assets and other income	12,798	26,903	133,958
Total revenues and other income	2,829,053	1,791,401	1,443,988
Costs and expenses			
Lease operating expenses	605,180	353,832	299,420
Severance and ad valorem taxes	47,959	52,072	43,618
Transportation, gathering and processing	176,315	75,043	—
Exploration expenses, including undeveloped lease amortization	95,105	101,812	120,389
Selling and general expenses	232,736	205,192	207,391
Depreciation, depletion and amortization	1,147,842	775,614	751,878
Accretion of asset retirement obligations	40,506	27,119	25,282
Impairment of assets	—	20,000	—
Other expense (benefit)	38,117	(34,870)	22,329
Total costs and expenses	2,383,760	1,575,814	1,470,307
Operating income (loss) from continuing operations	445,293	215,587	(26,319)
Other income (loss)			
Interest and other income (loss)	(22,520)	7,774	(78,302)
Interest expense, net	(219,275)	(180,359)	(178,263)
Total other loss	(241,795)	(172,585)	(256,565)
Income (loss) from continuing operations before income taxes	203,498	43,002	(282,884)
Income tax expense (benefit)	14,683	(126,136)	270,131
Income (loss) from continuing operations	188,815	169,138	(553,015)
Income from discontinued operations, net of income taxes	1,064,487	250,348	241,226
Net income (loss) including noncontrolling interest	1,253,302	419,486	(311,789)
Less: Net income attributable to noncontrolling interest	103,570	8,392	—
NET INCOME (LOSS) ATTRIBUTABLE TO MURPHY	$ 1,149,732	411,094	(311,789)
INCOME (LOSS) PER COMMON SHARE – BASIC			
Continuing operations	$ 0.52	0.92	(3.21)
Discontinued operations	6.49	1.46	1.40
Net income (loss)	$ 7.01	2.38	(1.81)
INCOME (LOSS) PER COMMON SHARE – DILUTED			
Continuing operations	$ 0.52	0.92	(3.21)
Discontinued operations	6.46	1.44	1.40
Net income (loss)	$ 6.98	2.36	(1.81)
Cash dividends per Common share	$ 1.00	1.00	1.00
Average Common shares outstanding (thousands)			
Basic	163,992	172,974	172,524
Diluted	164,812	174,209	172,524

[1] Reclassified to conform with current presentation (see Notes C and E). 2017 revenue is presented net of $58.9 million of transportation, gathering and processing costs as historically shown prior to the adoption of ASC 606 on January 1, 2018. See Notes to Consolidated Financial Statements, page 58.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Years Ended December 31 (Thousands of dollars)	**2019**	2018	2017
Net income (loss) including noncontrolling interest	$ **1,253,302**	419,486	(311,789)
Other comprehensive income (loss), net of tax			
Net gain (loss) from foreign currency translation	**66,600**	(145,022)	171,725
Retirement and postretirement benefit plans	**(35,979)**	29,110	(7,682)
Deferred loss on interest rate hedges reclassified to interest expense	**5,005**	2,342	1,926
Reclassification of certain tax effects to retained earnings	**—**	(30,237)	—
Other	**—**	(3,737)	—
Other comprehensive income (loss)	**35,626**	(147,544)	165,969
COMPREHENSIVE INCOME (LOSS)	$ **1,288,928**	271,942	(145,820)

See Notes to Consolidated Financial Statements, page 58.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 (Thousands of dollars)	2019	2018 [1]	2017 [1]
Operating Activities			
Net income (loss) including noncontrolling interest	$ **1,253,302**	419,486	(311,789)
Adjustments to reconcile net income (loss) to net cash provided by continuing operations activities:			
(Income) loss from discontinued operations	**(1,064,487)**	(250,348)	(241,226)
Depreciation, depletion and amortization	**1,147,842**	775,614	751,878
Previously suspended exploration costs (credits)	**12,840**	20,508	(4,861)
Amortization of undeveloped leases	**27,973**	40,177	61,775
Accretion of asset retirement obligations	**40,506**	27,119	25,282
Impairment of assets	**—**	20,000	—
Deferred income tax charge (benefit)	**28,530**	(177,627)	270,072
Pretax (gain) loss from sale of assets	**(227)**	(54)	(127,434)
Mark to market loss (gain) on contingent consideration	**8,672**	(4,810)	—
Mark to market loss (gain) on crude contracts	**33,364**	(33,954)	(13,748)
Long-term non-cash compensation	**76,958**	72,151	44,119
Net (increase) decrease in noncash operating working capital	**(16,887)**	(16,103)	78,846
Other operating activities, net	**(59,281)**	(142,764)	80,437
Net cash provided by continuing operations activities	**1,489,105**	749,395	613,351
Investing Activities			
Acquisition of oil and natural gas properties	**(1,212,315)**	(794,623)	—
Property additions and dry hole costs	**(1,344,271)**	(1,011,292)	(910,030)
Proceeds from sales of property, plant and equipment	**20,382**	1,175	69,506
Purchase of investment securities	**—**	—	(212,661)
Proceeds from maturity of investment securities	**—**	—	320,828
Net cash required by investing activities	**(2,536,204)**	(1,804,740)	(732,357)
Financing Activities			
Borrowings on revolving credit facility and term loan	**1,725,000**	325,000	—
Repayment of revolving credit facility and term loan	**(2,050,000)**	—	—
Debt issuance, net of cost	**542,394**	—	541,597
Early retirement of debt	**(521,332)**	—	(550,000)
Loss on early extinguishment of debt	**(26,626)**	—	—
Repurchase of common stock	**(499,924)**	—	—
Capital lease obligation payments	**(688)**	(318)	—
Withholding tax on stock-based incentive awards	**(6,991)**	(8,076)	(7,116)
Distributions to noncontrolling interest	**(128,158)**	—	—
Cash dividends paid	**(163,669)**	(173,044)	(172,565)
Net cash (required) provided by financing activities	**(1,129,994)**	143,562	(188,084)
Cash Flows from Discontinued Operations [2]			
Operating activities	**73,783**	406,857	527,228
Investing activities	**2,022,034**	(91,398)	(99,637)
Financing activities	**(4,914)**	(9,432)	(17,133)
Net cash provided by discontinued operations	**2,090,903**	306,027	410,458
Cash transferred from discontinued operations to continuing operations	**2,120,397**	612,543	325,446
Effect of exchange rate changes on cash and cash equivalents	**3,533**	28,730	1,327
Net increase (decrease) in cash and cash equivalents	**(53,163)**	(270,510)	19,683
Cash and cash equivalents at beginning of period	**359,923**	630,433	610,750
Cash and cash equivalents at end of period	$ **306,760**	**359,923**	**630,433**

[1] Reclassified to conform with current presentation (see Note E). [2] Net cash provided by discontinued operations are not part of the cash flow reconciliation. See Notes to Consolidated Financial Statements, page 58.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

Years Ended December 31 (Thousands of dollars except share amounts)	2019	2018	2017
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	$ —	—	—
Common Stock – par $1.00, authorized 450,000,000 shares at December 31, 2019, 2018 and 2017, issued 195,089,269 at December 31, 2019, 195,076,924 shares at December 31, 2018 and 195,055,724 at December 31, 2017			
Balance at beginning of year	**195,077**	195,056	195,056
Exercise of stock options	**12**	21	—
Balance at end of year	**195,089**	195,077	195,056
Capital in Excess of Par Value			
Balance at beginning of year	**979,642**	917,665	916,799
Exercise of stock options, including income tax benefits	**(182)**	(362)	—
Restricted stock transactions and other	**(38,731)**	(33,920)	(26,553)
Stock-based compensation	**33,235**	27,920	27,496
Fair value increase in common controlled assets	**(24,519)**	68,339	—
Other	**—**	—	(77)
Balance at end of year	**949,445**	979,642	917,665
Retained Earnings			
Balance at beginning of year	**5,513,529**	5,245,242	5,729,596
Net income (loss) for the year attributable to Murphy	**1,149,732**	411,094	(311,789)
Reclassification of certain tax effects from accumulated other comprehensive loss	**—**	30,237	—
Sale and leaseback gain recognized upon adoption of ASC 842, net of tax impact	**114,712**	—	—
Cash dividends	**(163,669)**	(173,044)	(172,565)
Balance at end of year	**6,614,304**	5,513,529	5,245,242
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(609,787)**	(462,243)	(628,212)
Foreign currency translation gains (losses), net of income taxes	**66,600**	(145,022)	171,725
Retirement and postretirement benefit plans, net of income taxes	**(35,979)**	29,110	(7,682)
Deferred loss on interest rate hedge reclassified to interest expense, net of income taxes	**5,005**	2,342	1,926
Reclassification of certain tax effects to retained earnings	**—**	(30,237)	—
Other	**—**	(3,737)	—
Balance at end of year	**(574,161)**	(609,787)	(462,243)
Treasury Stock			
Balance at beginning of year	**(1,249,162)**	(1,275,529)	(1,296,560)
Purchase of treasury shares	**(499,924)**	—	—
Sale of stock under employee stock purchase plans	**—**	—	146
Awarded restricted stock, net of forfeitures	**31,869**	26,367	20,885
Balance at end of year – 42,153,908 of Common Stock in 2019, 22,018,095 shares of Common Stock in 2018, and 22,482,851 shares of Common Stock in 2017	**(1,717,217)**	(1,249,162)	(1,275,529)
Murphy Shareholders' Equity	**5,467,460**	4,829,299	4,620,191
Noncontrolling Interest			
Balance at beginning of year	**368,343**	—	—
Acquisition	**—**	359,951	—
Acquisition closing adjustments	**(6,604)**	—	—
Net income attributable to noncontrolling interest	**103,570**	8,392	—
Distributions to noncontrolling interest owners	**(128,158)**	—	—
Balance at end of year	**337,151**	368,343	—
Total Equity	**$ 5,804,611**	5,197,642	4,620,191

See Notes to Consolidated Financial Statements, page 58.

These notes are an integral part of the financial statements of Murphy Oil Corporation and Consolidated Subsidiaries (Murphy/the Company) on pages 53-57 of the Form 10-K report.

Note A – Significant Accounting Policies

NATURE OF BUSINESS – Murphy Oil Corporation is an international oil and natural gas company that conducts its business through various operating subsidiaries. The Company primarily produces oil and natural gas in the United States and Canada and conducts oil and natural gas exploration activities worldwide. The Company sold its Canadian heavy oil assets in early 2017 and Malaysian assets in 2019. See Notes E and G for more information regarding the sale of these assets.

PRINCIPLES OF CONSOLIDATION – The consolidated financial statements include the accounts of Murphy Oil Corporation and all majority-owned subsidiaries. Undivided interests in oil and natural gas joint ventures are consolidated on a proportionate basis. Investments in affiliates in which the Company owns from 20% to 50% are accounted for by the equity method. Beginning in the fourth quarter of 2018, Murphy reports 100% of the sales volume, revenues, costs, assets and liabilities including the 20% noncontrolling interest (NCI), of MP GOM in accordance with accounting for noncontrolling interest as prescribed by ASC 810-10-45 (see Note D). Other investments are generally carried at cost. All significant intercompany accounts and transactions have been eliminated.

REVENUE RECOGNITION – Revenues from sales of crude oil, natural gas liquids and natural gas are recorded when deliveries have occurred and legal ownership of the commodity transfers to the 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. Revenues from the production of oil and natural gas properties in which Murphy shares in the undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Natural gas imbalances occur when the Company's actual natural gas sales volumes differ from its proportional share of production from the well. The company follows the sales method of accounting for these natural gas imbalances. The Company records a liability for natural gas imbalances when it has sold more than its working interest of natural gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2019 and 2018, the liabilities for natural gas balancing were immaterial. Gains and losses on asset disposals or retirements are included in net income/(loss) as a component of revenues. See Note B for further discussion on revenue recognition.

CASH EQUIVALENTS – Short-term investments, which include government securities and other instruments with government securities as collateral, that are highly liquid and have a maturity of three months or less from the date of purchase are classified as cash equivalents.

MARKETABLE SECURITIES – The Company classifies investments in marketable securities as available-for-sale or held-to-maturity. The Company does not have any investments classified as trading securities. Available-for-sale securities are carried at fair value with the unrealized gain or loss, net of tax, reported in other comprehensive loss. Held-to-maturity securities are recorded at amortized cost. Premiums and discounts are amortized or accreted into earnings over the life of the related available-for-sale or held-to-maturity security. Dividend and interest income is recognized when earned. Unrealized losses considered to be other than temporary are recognized in earnings. The cost of securities sold is based on the specific identification method. The fair value of investment securities is determined by available market prices.

ACCOUNTS RECEIVABLE – At December 31, 2019 and 2018, the Company's accounts receivable primarily consisted of amounts owed to the Company by customers for sales of crude oil and natural gas. The allowance for doubtful accounts is the Company's best estimate of the amount of probable credit losses on these receivables. The Company reviews this allowance for adequacy at least quarterly and bases its assessment on a combination of current information about its customers and historical write-off experience. Any trade accounts receivable balances written off are charged against the allowance for doubtful accounts. The Company has not experienced any significant credit-related losses in the past three years.

INVENTORIES – Amounts included in the Consolidated Balance Sheets include unsold crude oil production and materials and supplies associated with oil and natural gas production operations. Unsold crude oil production is carried in inventory at the lower of cost (applied on a first-in, first-out basis and includes costs incurred to bring the inventory to its existing condition), or market. Materials and supplies inventories are valued at the lower of average cost or estimated market value and generally consist of tubulars and other drilling equipment.

PROPERTY, PLANT AND EQUIPMENT – The Company uses the successful efforts method to account for exploration and development expenditures. Leasehold acquisition costs are capitalized. If proved reserves are found on undeveloped property, the leasehold cost is transferred to proved properties. Costs of undeveloped leases associated with unproved properties are expensed over the life of the leases. Exploratory well costs are capitalized pending determination about whether proved reserves have been found. In certain cases, a determination of whether a drilled exploratory well has found proved reserves cannot be made immediately. This is generally due to the need for major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such capital expenditure is usually dependent on whether further exploratory or appraisal wells find a sufficient quantity of additional reserves. The Company continues to capitalize exploratory well costs in Property, Plant and Equipment 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. The Company reevaluates its capitalized drilling costs at least annually to ascertain whether drilling costs continue to qualify for ongoing capitalization. Other exploratory costs, including geological and geophysical costs, are charged to expense as incurred. Development costs, including unsuccessful development wells, are capitalized. Interest is capitalized on significant development projects that are expected to take one year or more to complete.

Oil and natural gas properties are evaluated by field for potential impairment. Other properties are evaluated for impairment on a specific asset basis or in groups of similar assets as applicable. An impairment is recognized when there are indications that the estimated undiscounted future net cash flows of an asset are less than its carrying value. If an impairment occurs, the carrying value of the impaired asset is reduced to fair value. There were no impairments in 2019. As a result of management's assessments during 2018, the Company recognized a pretax, noncash impairment charge of $20.0 million at select Midland properties. There were no impairments recorded during 2017. See also Note G for further discussion of impairment charges.

The Company records a liability for asset retirement obligations (ARO) equal to the fair value of the estimated cost to retire an asset. The ARO liability is initially recorded in the period in which the obligation meets the definition of a liability, which is generally when a well is drilled or the asset is placed in service. The ARO liability is estimated by the Company's engineers using existing regulatory requirements and anticipated future inflation rates. When the liability is initially recorded, the Company increases the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is increased over time to reflect the change in its present value, and the capitalized cost is depreciated over the useful life of the related long-lived asset. The Company reevaluates the adequacy of its recorded ARO liability at least annually. Actual costs of asset retirements such as dismantling oil and natural gas production facilities and site restoration are charged against the related liability.

Any difference between costs incurred upon settlement of an asset retirement obligation and the recorded liability is recognized as a gain or loss in the Company's earnings.

Depreciation and depletion of producing oil and natural gas properties are recorded based on units of production. Unit rates are computed for unamortized development drilling and completion costs using proved developed reserves and acquisition costs are amortized over proved reserves. Proved reserves are estimated by the Company's engineers and are subject to future revisions based on the availability of additional information.

CAPITALIZED INTEREST– Interest associated with borrowings from third parties is capitalized on significant oil and natural gas development projects when the expected development period extends for one year or more. Interest capitalized is credited in the Consolidated Statements of Operations and is added to the cost of the underlying asset for the development project in Property, plant and equipment in the Consolidated Balance Sheets. Capitalized interest is amortized over the useful life of the asset in the same manner as other development costs.

LEASES - At inception, contracts are assessed for the presence of a lease according to criteria laid out by ASC 842. If a lease is present, further criteria is assessed to determine if the lease should be classified as an operating or finance lease. Operating leases are presented on the Consolidated Balance Sheet as Operating lease assets with the corresponding lease liabilities presented in Operating lease liabilities and Non-current operating lease liabilities. Finance lease assets are presented on the Consolidated Balance Sheet within Assets held for sale with the corresponding liabilities presented in Current maturities of long-term debt and Long-term debt.

Generally, lease liabilities are recognized at commencement and based on the present value of the future minimum lease payments to be made over the lease term. Lease assets are then recognized based on the value of the lease liabilities. Where implicit lease rates are not determinable, the minimum lease payments are discounted using the Company's collateralized incremental borrowing rates.

Operating leases are expensed according to their nature and recognized in Lease operating expenses, Selling and general expenses or capitalized in the Consolidated Financial Statements. Finance leases are depreciated with the relevant expenses recognized in Depreciation, depletion, and amortization and Interest expense, net on the Consolidated Statement of Operations.

ENVIRONMENTAL LIABILITIES – A liability for environmental matters is established when it is probable that an environmental obligation exists and the cost can be reasonably estimated. If there is a range of reasonably estimated costs, the most likely amount will be recorded, or if no amount is most likely, the minimum of the range is used. Related expenditures are charged against the liability. Environmental remediation liabilities have not been discounted for the time value of future expected payments. Environmental expenditures that have future economic benefit are capitalized.

INCOME TAXES – The Company accounts for income taxes using the asset and liability method. Under this method, income taxes are provided for amounts currently payable and for amounts deferred as tax assets and liabilities based on differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. Deferred income taxes are measured using the enacted tax rates that are assumed will be in effect when the differences reverse. The Company routinely assesses the realizability of deferred tax assets based on available evidence including assumptions of future taxable income, tax planning strategies and other pertinent factors. A deferred tax asset valuation allowance is recorded when evidence indicates that it is more likely than not that all or a portion of these deferred tax assets will not be realized in a future period.

On December 22, 2017 the Tax Cuts and Jobs Act (2017 Tax Act) was enacted which triggered the transitional tax on a deemed repatriation of all past foreign earnings (see Note J) and a provision for this impact has been recorded. Deferred tax liabilities are recorded for relevant withholding taxes when undistributed earnings of foreign subsidiaries are not considered indefinitely invested. Under present law, the Company would incur a 5% withholding tax on any earnings repatriated from Canada to the U.S.

The accounting rules for income tax uncertainties permit recognition of income tax benefits only when they are more likely than not to be realized, and then only for the largest amount that is greater than 50% likely of being realized. The Company includes potential penalties and interest for uncertain income tax positions in income tax expense.

FOREIGN CURRENCY – Local currency is the functional currency used for recording operations in Canada and former refining and marketing activities in the United Kingdom. The U.S. dollar is the functional currency used to record all other operations. Exchange gains or losses from transactions in a currency other than the functional currency are included in earnings as part of Interest and other income (loss). Gains or losses from translating foreign functional currencies into U.S. dollars are included in Accumulated Other Comprehensive Loss in Consolidated Statements of Stockholders' Equity.

DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES – The fair value of a derivative instrument is recognized as an asset or liability in the Company's Consolidated Balance Sheets. Upon entering into a derivative contract, the Company may designate the derivative as either a fair value hedge or a cash flow hedge or decide that the contract is not a hedge for accounting purposes, and thenceforth, recognize changes in the fair value of the contract in earnings. The Company documents the relationship between the derivative instrument designated as a hedge and the hedged items as well as its objective for risk management and strategy for the use of the hedging instrument to manage the risk. Derivative instruments designated as fair value or cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The Company assesses at inception and on an ongoing basis whether a derivative instrument accounted for as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting. The change in the fair value of a qualifying fair value hedge is recorded in earnings along with the gain or loss on the hedged item. The effective portion of the change in the fair value of a qualifying cash flow hedge is recorded in Accumulated other comprehensive loss in the Consolidated Balance Sheets until the hedged item is recognized currently in earnings. If a derivative instrument no longer qualifies as a cash flow hedge and the underlying forecasted transaction is no longer probable of occurring, hedge accounting is discontinued, and the gain or loss recorded in Accumulated other comprehensive loss is recognized immediately in earnings.

FAIR VALUE MEASUREMENTS– The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheets. Fair value is determined using various techniques depending on the availability of observable inputs. Level 1 inputs include quoted prices in active markets for identical assets or liabilities. Level 2 inputs include observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs which reflect assumptions about pricing by market participants. See Note Q.

STOCK-BASED COMPENSATION
Equity-Settled Awards – The fair value of awarded stock options, restricted stock units and other stock-based compensation that are settled with Company shares is determined based on a combination of management assumptions and the market value of the Company's common stock. The Company uses the Black-Scholes option pricing model for computing the fair value of equity-settled stock options. The primary assumptions made by management include the expected life of the stock option award and the expected volatility of Murphy's common stock price. The Company uses both historical data and current information to support its assumptions. Stock option expense is recognized on a straight-line basis over the respective vesting period of two or three years. The Company uses a Monte Carlo valuation model to determine the fair value of performance-based restricted stock units that are equity settled and expense is recognized over the three-year vesting period. The fair value of time-lapse restricted stock units is determined based on the price of Company stock on the date of grant and expense is recognized over the vesting period. The Company estimates the number of stock options and performance-based restricted stock units that will not

vest and adjusts its compensation expense accordingly. Differences between estimated and actual vested amounts are accounted for as an adjustment to expense when known.

Cash-Settled Awards – The Company accounts for stock appreciation rights (SAR), cash-settled restricted stock units (CRSU) and phantom stock units as liability awards. Expense associated with these awards are recognized over the vesting period based on the latest available estimate of the fair value of the awards, which is generally determined using a Black-Scholes method for SAR, a Monte Carlo method for performance-based CRSU, and the period-end price of the Company's common stock for time-based CRSU and phantom units. When SAR are exercised and when CRSU and phantom units settle, the Company adjusts previously recorded expense to the final amounts paid out in cash for these awards. See Note K.

PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS – The Company recognizes the funded status (the difference between the fair value of plan assets and the projected benefit obligation) of its defined benefit and other postretirement benefit plans in the Consolidated Balance Sheets. Changes in the funded status which have not yet been recognized in the Consolidated Statement of Operations are recorded net of tax in Accumulated other comprehensive loss. The remaining amounts in Accumulated other comprehensive loss include net actuarial losses and prior service (cost) credit. See Note L.

NET INCOME (LOSS) PER COMMON SHARE – Basic income (loss) per common share is computed by dividing net income (loss) for each reporting period by the weighted average number of common shares outstanding during the period. Diluted income (loss) per common share is computed by dividing net income (loss) for each reporting period by the weighted average number of common shares outstanding during the period plus the effects of all potentially dilutive common shares. Dilutive securities are not included in the computation of diluted income (loss) per share when a net loss occurs as the inclusion would have the effect of reducing the diluted loss per share.

USE OF ESTIMATES – In preparing the financial statements of the Company in conformity with U.S. generally accepted accounting principles (GAAP), 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.

Note B – New Accounting Principles and Recent Accounting Pronouncements

Accounting Principles Adopted

Leases. In February 2016, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) 2016-02 *(Topic 842)* 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 company adopted the standard in the first quarter of 2019 utilizing the modified retrospective transition method through a cumulative-effect adjustment at the beginning of the first quarter of 2019. The Company has elected the package of practical expedients, which allows the Company not to reassess (1) whether any expired or existing contracts as of the adoption date are or contain a lease, (2) lease classification for any expired or existing leases as of the adoption date and (3) initial direct costs for any existing leases as of the adoption date. The Company did not elect to apply the hindsight practical expedient when determining lease term and assessing impairment of right-of-use assets. The adoption of ASU 2016-02 resulted in the initial recognition of right-of-use assets of $618.1 million, current lease liabilities for operating leases of approximately $155.5 million, non-current lease liabilities of $468.4 million and a cumulative-effect adjustment to credit retained earnings of $114.7 million on its Consolidated Balance Sheets, with no material impact to its Consolidated Statements of Operations. See Note V for further information regarding the impact of the adoption of ASU 2016-02 on the Company's financial statements.

Compensation – Stock Compensation. In June 2018, the FASB issued an ASU 2018-07 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 Company adopted this guidance during the first quarter of 2019 and it did not have material impact on its consolidated financial statements.

In May 2017, the FASB issued ASU 2017-9 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 a material impact on its consolidated financial statements.

Compensation-Retirement Benefits-Defined Benefit Plans-General. In March 2017, the FASB issued ASU 2017-7 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 elected to apply the practical expedient, which allows us to reclassify amounts disclosed previously in the retirement benefits note as the basis for applying retrospective presentation for comparative periods. The Company adopted the standard in the first quarter of 2018 and it did not have a material impact on its consolidated financial statements.

Revenue from Contracts with Customers. In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-9, 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 uncertainty 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 - *Revenue Recognition*, 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 the application of the new ASU promulgated in ASC Topic 606 using the modified retrospective method. The 2017 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 ASU 2016-15 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.

Statement of Operations – Reporting Comprehensive Income. In February 2018, the FASB issued ASU 2018-2, 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 the deferred loss on interest rate derivative hedges. The adoption of this ASU will have no future impact.

SEC Disclosures Update and Simplification. In August 2018, the U.S. Securities and Exchange Commission (SEC) adopted the final rule under SEC Release No. 33-10532 Disclosure Update and Simplification, to eliminate or modify certain disclosure rules that are redundant, outdated, or duplicative of U.S. GAAP or other regulatory requirements. Among other changes, the amendments eliminated the annual requirement to disclose the high and low trading prices of our common stock and the ratio of earnings to fixed charges. In addition, the amendments provide that disclosure requirements related to the analysis of shareholders' equity are expanded for interim financial statements. An analysis of the changes in each caption of shareholders' equity presented in the balance sheet must be provided in a note or separate statement, as well as the amount of dividends per share for each class of shares. This rule was effective on November 5, 2018; and the expanded interim disclosure requirements for changes in shareholders' equity was effective for the Company for our quarterly reporting beginning March 31, 2019.

Recent Accounting Pronouncements

Financial Instruments – Credit Losses. In June 2016, the FASB issued ASU 2016-13 which replaces the impairment model for most financial assets, including trade receivables, from the incurred loss methodology to a forward-looking expected loss model that will result in earlier recognition of credit losses. The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, with early adoption permitted, and is to be applied on a modified retrospective basis. The Company adopted this accounting standard in the first quarter of 2020 and it did not have a material impact on its consolidated financial statements.

Fair Value Measurement. In August 2018, the FASB issued ASU 2018-13 which modifies disclosure requirements related to fair value measurement. The amendments in this ASU are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. Implementation on a prospective or retrospective basis varies by specific disclosure requirement. Early adoption is permitted. The standard also allows for early adoption of any removed or modified disclosures upon issuance of this ASU while delaying adoption of the additional disclosures until their effective date. The Company adopted this accounting standard in the first quarter of 2020 and it did not have a material impact on its consolidated financial statements.

Income Taxes. In December 2019, the FASB issued ASU 2019-12, which removes certain exceptions for investments, intraperiod allocations and interim calculations, and adds guidance to reduce complexity in accounting for income taxes. The amendments in this ASU are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. Implementation on a prospective or retrospective basis varies by specific topics within the ASU. Early adoption is permitted. The Company is currently assessing the potential impact of this ASU to its consolidated financial statements.

Compensation-Retirement Benefits-Defined Benefit Plans-General. In August 2018, the FASB issued ASU 2018-14 which modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. For public companies, the amendments in this ASU are effective for fiscal years beginning after December 15, 2020, with early adoption permitted, and is to be applied on a retrospective basis to all periods presented. The Company is currently assessing the potential impact of this ASU to its consolidated financial statements.

Note C – Revenue from Contracts with Customers

Nature of Goods and Services

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

For operated oil and natural 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. The exception to this is the reporting of the noncontrolling interest in MP GOM as prescribed by ASC 810-10-45.

U.S.- In the United States, the Company primarily produces oil and natural 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 natural gas are transferred to the customer at the delivery point. Revenue recognized is largely index based with price adjustments for floating market differentials.

Canada- In Canada, contracts associated with the Onshore business, are primarily long-term floating commodity index priced, except for certain natural gas physical forward sales fixed-price contracts. 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.

In 2019, the Company made an immaterial reclassification to correct its financial statements to report transportation, gathering, and processing costs as a separate line item (previously reported net in revenue) in the Consolidated Statements of Operations and revised the 2018 period to reflect this presentation. There was no resultant change in net income attributable to Murphy. The Company did not revise 2017 as it was presented in accordance with ASC 605.

Disaggregation of Revenue

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

For the years ended December 31, 2019, 2018, and 2017 the Company recognized $2,817.1 million, $1,806.5 million and $1,300.5 million, respectively, from contracts with customers for the continuing operations sales of oil, natural gas liquids and natural gas.

		Years Ended December 31,		
(Thousands of dollars)		**2019**	2018	2017
Net crude oil and condensate revenue				
United States	Onshore	**$ 750,278**	786,537	644,024
	Offshore	**1,477,816**	417,527	208,984
Canada	Onshore	**116,174**	111,836	51,013
	Offshore	**159,254**	176,291	147,230
Other		**11,642**	6,079	—
Total crude oil and condensate revenue		**2,515,164**	1,498,270	1,051,251
Net natural gas liquids revenue				
United States	Onshore	**30,615**	61,810	43,804
	Offshore	**26,968**	11,832	6,894
Canada	Onshore	**12,001**	14,670	5,450
Total natural gas liquids revenue		**69,584**	88,312	56,148
Net natural gas revenue				
United States	Onshore	**27,668**	36,070	27,460
	Offshore	**46,259**	17,559	10,480
Canada	Onshore	**158,436**	166,262	155,125
Total natural gas revenue		**232,363**	219,891	193,065
Total revenue from contracts with customers [1]		**2,817,111**	1,806,473	1,300,464
Gain (loss) on crude contracts		**(856)**	(41,975)	9,566
Gain on sale of assets and other income [2]		**12,798**	26,903	133,958
Total revenue and other income		**$ 2,829,053**	1,791,401	1,443,988

[1] 2019 and 2018 include revenue attributable to noncontrolling interest in MP GOM, effective November 30, 2018.

[2] Gain on sale of Malaysia operations of $985.4 million in 2019 is reported in discontinued operations. See Note E.

Contract Balances and Asset Recognition

As of December 31, 2019, and 2018, receivables from contracts with customers, net of royalties and associated payables, on the balance sheet from continuing operations, were $186.8 million and $147.6 million, respectively. Payment terms for the Company'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 natural gas sale contracts that have financing components as of December 31, 2019.

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.

Performance Obligations

The Company recognizes oil and natural 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 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.

As of December 31, 2019, 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 December 31, 2019

Location	Commodity	End Date	Description	Approximate Volumes
U.S.	NGL	Q4 2020	Dedicated acreage delivery in GOM	As produced
U.S.	Oil	Q4 2021	Fixed quantity delivery in Eagle Ford	17,000 BOED
U.S.	Natural Gas and NGL	Q2 2026	Deliveries from dedicated acreage in Eagle Ford	As produced
Canada	Natural Gas	Q4 2020	Contracts to sell natural gas at Alberta AECO fixed prices	59 MMCFD
Canada	Natural Gas	Q4 2020	Contracts to sell natural gas at USD Index pricing	60 MMCFD
Canada	Natural Gas	Q4 2021	Contracts to sell natural gas at USD Index pricing	10 MMCFD
Canada	Natural Gas	Q4 2024	Contracts to sell natural gas at USD Index pricing	30 MMCFD
Canada	Natural Gas	Q4 2026	Contracts to sell natural gas at USD Index pricing	38 MMCFD
Canada	Natural Gas	Q4 2026	Contracts to sell natural gas at USD Index pricing	11 MMCFD

Note D – Acquisitions

PAI Transaction:

In December 2018, the Company announced the completion of a transaction with Petrobras Americas Inc. (PAI) which was effective October 1, 2018. Through this transaction, Murphy acquired all of PAI's producing Gulf of Mexico assets along with certain blocks that hold deep exploration rights. This transaction added approximately 97 MMBOE (including noncontrolling interest, NCI) of proven reserves at December 31, 2018.

Under the terms of the transaction, Murphy paid cash consideration of $780.7 million, after adjustments provided for in the sale and purchase agreement, and transferred a 20% interest in MP Gulf of Mexico, LLC (MP GOM), a subsidiary of Murphy, to PAI. Murphy also has an obligation to pay additional contingent consideration up to $150 million if certain sales thresholds are exceeded beginning in 2019 through 2025 (see Note Q for the contingent consideration liability balance as of December 31, 2019 and 2018 for the remainder of the covered periods). The revenue threshold was not exceeded in 2019 and no contingent consideration is payable related to the 2019 period. Both companies contributed all of their then-currently producing Gulf of Mexico assets into MP GOM. MP GOM is owned 80% by Murphy and 20% by PAI, with Murphy overseeing the operations.

LLOG Transaction:

In June 2019, the Company announced the completion of a transaction with LLOG Exploration Offshore L.L.C. and LLOG Bluewater Holdings, L.L.C., (LLOG) which was effective January 1, 2019. Through this transaction, Murphy acquired strategic deepwater Gulf of Mexico assets which added approximately 67 MMBOE of proven reserves at May 31, 2019.

Under the terms of the transaction, Murphy paid cash consideration of $1,238.4 million and has an obligation to pay additional contingent consideration of up to $200 million in the event that certain revenue thresholds are exceeded between 2019 and 2022, and $50 million following first oil from certain development projects (see Note Q for the contingent consideration liability balance as of December 31, 2019 and 2018 for the remainder of the covered periods). The revenue threshold was not exceeded in 2019 and no contingent consideration is payable related to the 2019 period.

The following table contains the purchase price allocations at fair value:

(Thousands of dollars)	PAI (Final)	LLOG (Preliminary)
Cash consideration paid	$ 780,678	$ 1,238,353
Fair value of net assets contributed	154,468	—
Contingent consideration	52,540	89,444
NCI in acquired assets	246,922	—
Total purchase consideration	$ 1,234,608	$ 1,327,797
(Thousands of dollars)		
Fair value of Property, plant and equipment	1,617,371	1,358,372
Other assets	5,628	6,697
Less: Asset retirement obligations	(388,391)	(37,272)
Total net assets	$ 1,234,608	$ 1,327,797

The fair value measurements of crude oil and natural gas properties and asset retirement obligations are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert expected future cash flows to a single discounted amount. Significant inputs to the valuation of crude oil and natural gas properties included estimates of: (i) proved and probable reserves; (ii) production rates and related development timing; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted average discount rate. These inputs require significant judgments and estimates by management at the time of the valuation, are sensitive, and may be subject to change.

Certain data necessary to complete the LLOG purchase price allocation is not yet available, and includes, but is not limited to, analysis of the underlying tax basis of the assets acquired and liabilities assumed as well as the final purchase price adjustments to be settled in 2020. We expect to complete the purchase price allocation during the 12-month period following the acquisition date, during which time the value of the assets and liabilities may be revised as appropriate.

Results of Operations

Murphy's Consolidated Statement of Operations for the year ended December 31, 2019, included additional revenues of $278.7 million and pre-tax income of $60.1 million attributable to the acquired LLOG assets.

Pro Forma Financial Information

The following pro forma condensed combined financial information was derived from historical financial statements of Murphy, PAI and LLOG and gives effect to the transaction as if it had occurred on January 1, 2018. The information below reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including depletion of LLOG fair-valued proved crude oil and natural gas properties. The pro forma condensed combined financial information was also adjusted to exclude acquisition-related costs of $6.2 million incurred by Murphy. The pro forma results of operations do not include any cost savings or other synergies that we expect to realize from the transaction or any estimated costs that have been or will be incurred by us to integrate the PAI or LLOG assets. The pro forma condensed combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have occurred had the transaction taken place on January 1, 2018; furthermore, the financial information is not intended to be a projection of future results.

Note D – Acquisition (Contd.)

	Years Ended December 31,	
(Thousands of dollars, except per share amounts)	**2019**	2018
Revenues	**$ 3,061,575**	3,290,104
Net Income Attributable to Murphy	**1,209,380**	758,639
Net Income Attributable to Murphy per Common Share		
Basic	**$ 7.37**	4.39
Diluted	**7.34**	4.35

Note E - Assets Held for Sale and Discontinued Operations

The following table presents the carrying value of the major categories of assets and liabilities of the Brunei exploration and production and the U.K. refining and marketing operations reflected as held for sale on the Company's Consolidated Balance Sheets at December 31, 2019. As of December 31, 2018, Malaysia exploration and production business was also held for sale. The Malaysia sale closed on July 10, 2019.

(Thousands of dollars)	**2019**	2018
Current assets		
Cash	**$ 25,185**	44,669
Accounts receivable	**4,834**	103,158
Inventories	**406**	7,887
Prepaid expenses and other	**1,882**	18,151
Property, Plant, and Equipment, net	**82,116**	—
Deferred income taxes and other assets	**9,441**	—
Total current assets associated with assets held for sale	**123,864**	173,865
Non-current assets		
Property, Plant, and Equipment, net	**—**	1,325,431
Deferred income taxes and other assets	**—**	219,577
Total non-current assets associated with assets held for sale	**—**	1,545,008
Current liabilities		
Accounts payable	**3,702**	203,236
Other accrued liabilities	**—**	55,273
Current maturities of long-term debt (finance lease)	**705**	9,915
Taxes payable	**1,411**	18,034
Asset retirement obligation	**240**	—
Long-term debt (finance lease)	**7,240**	—
Total current liabilities associated with assets held for sale	**13,298**	286,458
Non-current liabilities		
Long-term debt	**—**	117,816
Asset retirement obligation	**—**	274,904
Total non-current liabilities associated with assets held for sale	**$ —**	392,720

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued
Note E – Assets Held for Sale and Discontinued Operations (Contd.)

The Company has accounted for its former Malaysian exploration and production operations, along with 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 are presented in the following table.

(Thousands of dollars)		**2019**	2018	2017
Revenues [1]	$	**1,364,943**	854,251	781,995
Costs and expenses				
Lease operating expense		**127,138**	202,062	168,903
Depreciation, depletion and amortization		**33,697**	196,287	205,841
Other costs and expenses (benefits)		**81,538**	70,088	53,409
Total income from discontinued operations before taxes		**1,122,570**	385,814	353,842
Income tax expense		**58,083**	135,466	112,616
Income from discontinued operations	$	**1,064,487**	250,348	241,226

[1] 2019 includes a $985.4 million gain on sale of the Malaysia operations.

Note F – Inventories

Inventories consisted of the following at December 31, 2019 and 2018.

		December 31,	
(*Thousands of dollars*)		**2019**	2018
Unsold crude oil	$	**27,634**	17,318
Materials and supplies		**48,489**	62,706
Inventories	$	**76,123**	80,024

Note G – Property, Plant and Equipment

		December 31, 2019		December 31, 2018	
(Thousands of dollars)		**Cost**	**Net**	Cost	Net
Exploration and production [1]	$	**19,096,323**	**9,875,727** [2]	16,309,149	8,329,514 [2]
Corporate and other		**207,066**	**94,016**	193,471	102,619
Property, plant and equipment	$	**19,303,389**	**9,969,743**	16,502,620	8,432,133
[1] Includes unproved mineral rights as follows:	$	**508,526**	**121,163**	512,025	144,912

[2] Includes $24,698 in 2019 and $27,915 in 2018 related to administrative assets and support equipment.

Divestments

In July 2019, the Company completed a divestiture of its two subsidiaries conducting Malaysian operations, Murphy Sabah Oil Co., Ltd. and Murphy Sarawak Oil Co., Ltd., in a transaction with PTT Exploration and Production Public Company Limited (PTTEP) which was effective January 1, 2019. Total cash consideration received upon closing was $2.0 billion. A gain on sale of $985.4 million was recorded as part of discontinued operations on the Consolidated Statement of Operations in 2019. The Company does not anticipate tax liabilities related to the sales proceeds. Murphy is entitled to receive a $100.0 million bonus payment contingent upon certain future exploratory drilling results prior to October 2020.

In 2017, a Canadian subsidiary of the Company completed its disposition of the Seal field in onshore Canada. Total cash consideration to Murphy upon closing of the transaction was $48.8 million. Additionally, the buyer assumed the asset retirement obligation of approximately $85.9 million. A $129.0 million pretax gain was reported in 2017 on the Consolidated Statement of Operations related to the sale.

Acquisitions

In June 2019, the Company announced the completion of a transaction with LLOG Exploration Offshore L.L.C. and LLOG Bluewater Holdings, L.L.C., (LLOG) which was effective January 1, 2019. Through this transaction, Murphy acquired strategic deepwater Gulf of Mexico assets which added approximately 67 MMBOE of proven reserves at May 31, 2019.

Under the terms of the transaction, Murphy paid cash consideration of $1,238.4 million and has an obligation to pay additional contingent consideration of up to $200 million in the event that certain revenue thresholds are exceeded between 2019 and 2022; and $50 million following first oil from certain development projects.

In 2018, a wholly owned subsidiary, Murphy Exploration & Production Company - USA, entered into a definitive agreement with Petrobras America Inc. (PAI), a subsidiary of Petrobras. The transaction was comprised of all of the Gulf of Mexico producing assets from Murphy and PAI with Murphy overseeing the operations. Both companies contributed all their current producing Gulf of Mexico assets to MP Gulf of Mexico, LLC, a subsidiary of Murphy, which following closing of the transaction is owned 80% by Murphy and 20% by PAI. The transaction excluded Murphy's exploration blocks. However, PAI's blocks that hold deep exploration rights were part of the transaction. Murphy paid net cash consideration of $780.7 million, after adjustments provided for in the sale and purchase agreement. Additionally, PAI received a 20% interest in MP GOM and will earn an additional contingent consideration of up to $150 million if certain price and production thresholds are exceeded beginning in 2019 through 2025. Also, Murphy will carry $50 million of PAI development costs in the St. Malo Field if certain enhanced oil recovery projects are undertaken.

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 December 31, 2019, $152.7 million of the carried interest had been paid and the remainder is expected to be paid in the first quarter of 2020.

Impairments

During 2018, declines in future oil and natural gas prices led to impairments in certain of the Company's producing properties. During 2018, the Company recorded pretax noncash impairment charges of $20.0 million to reduce the carrying values to their estimated fair values at select Midland properties.

The following table reflects the recognized impairments for the three years ended December 31, 2019.

	December 31,		
(Thousands of dollars)	**2019**	2018	2017
U.S. Onshore (Midland)	**$ —**	20,000	—
	$ —	20,000	—

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 December 31, 2019, 2018 and 2017, the Company had total capitalized drilling costs pending the determination of proved reserves of $217.3 million, $207.9 million and $155.1 million, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2019.

(Thousands of dollars)	**2019**	2018	2017
Beginning balance at January 1	**$ 207,855**	155,103	101,546
Additions pending the determination of proved reserves	**83,712**	59,487	53,557
Reclassifications to proved properties based on the determination of proved reserves	**(61,096)**	(2,214)	—
Capitalized exploration well costs charged to expense	**(13,145)**	(4,521)	—
Ending balance at December 31	**$ 217,326**	207,855	155,103

The capitalized well costs charged to expense during 2019 included the CM-1X and the CT-1X wells in Vietnam Block 11-2/11. The wells were originally drilled in 2017. The capitalized well costs charged to expense during 2018 included the Julong East well in Block CA-1, offshore Brunei in which further development of the well has not been sanctioned by the operator and the contract term for development sanctions was reached. This well was originally drilled in 2012.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued
Note G – Property, Plant and Equipment (Contd.)

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

	2019			2018			2017		
(Thousands of dollars)	**Amount**	**No. of Wells**	**No. of Projects**	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects
Aging of capitalized well costs:									
Zero to one year	**$ 63,409**	**5**	**5**	$ 61,096	1	1	$ 41,480	3	2
One to two years	**—**	**—**	**—**	40,523	3	2	5,812	1	1
Two to three years	**27,396**	**1**	**—**	5,208	1	1	43,200	2	2
Three years or more	**126,521**	**5**	**—**	101,028	4	1	64,611	6	1
	$ 217,326	**11**	**5**	$ 207,855	9	5	$ 155,103	12	6

Of the $153.9 million of exploratory well costs capitalized more than one year at December 31, 2019, $57.5 million is in Brunei, $69.1 million is in Vietnam, and $27.4 million is in the U.S. In all geographical areas, either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion.

Note H – Financing Arrangements and Long-Term Debt

As of December 31, 2019, the Company has a $1.6 billion revolving credit facility (RCF). The RCF is a senior unsecured guaranteed facility which expires in November 2023. At December 31, 2019, the Company had no outstanding borrowings under the RCF and $3.7 million of outstanding letters of credit, which reduces the borrowing capacity of the RCF. At December 31, 2019, the interest rate in effect on borrowings under the facility would have been 3.21%. At December 31, 2019, the Company was in compliance with all covenants related to the RCF.

In May 2019, the Company entered into a $500 million term loan credit facility (the New Term Credit Facility). The New Term Credit Facility was a senior unsecured guaranteed facility with an original maturity date of December 2, 2019. The covenants within the New Term Credit Facility were substantially consistent with those in the Company’s revolving credit facility (see RCF above), and borrowings under the New Term Credit Facility bore interest at comparable rates to those incurred under the 2018 facility. In July 2019, the Company closed the previously announced Malaysia divestiture, repaid and terminated the New Term Credit Facility.

In November 2019, the Company sold $550 million of new notes that bear interest at a rate of 5.875% and mature on December 1, 2027. The Company incurred transaction costs of $7.4 million on the issuance of these new notes. The Company will pay interest semi-annually on June 1 and December 1 of each year, beginning June 1, 2020. The proceeds of the $550 million notes were used to repurchase and cancel $239.7 million of the Company’s 4.00% notes due 2022 and $281.6 million of the Company’s 4.45% notes due 2022 (originally issued as 3.70% notes due 2022, see table footnote below) (collectively the 2022 Notes) during November and December. The cost of the debt extinguishment of $32.1 million is included in Interest expense, net on the Consolidated Statement of Operations for the year ended December 31, 2019. The cash costs of $26.6 million are shown as a financing activity on the Consolidated Statement of Cash Flows for the year ended December 31, 2019.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued
Note H – Financing Arrangements and Long-Term Debt (Contd.)

	December 31,	
(Thousands of dollars)	**2019**	**2018**
Notes payable		
4.00% notes, due June 2022	$ **260,251**	500,000
4.45% notes, due December 2022 [1]	**318,417**	600,000
6.875% notes, due August 2024	**550,000**	550,000
5.75% notes, due August 2025	**550,000**	550,000
5.875% notes, due December 2027	**550,000**	—
7.05% notes, due May 2029	**250,000**	250,000
5.875% notes, due December 2042 [1]	**350,000**	350,000
Total notes payable	**2,828,668**	2,800,000
Unamortized debt issuance cost and discount on notes payable	**(25,287)**	(23,627)
Total notes payable, net of unamortized discount	**2,803,381**	2,776,373
Capitalized lease obligation, due through March 2029 [1]	**—**	8,613
Total debt including current maturities	**2,803,381**	2,784,986
Senior Unsecured Revolving Credit Facility	**—**	325,000
Current maturities [2]	**—**	(668)
Total long-term debt	$ **2,803,381**	3,109,318

[1] Coupon rate may fluctuate 25 basis points if rating is periodically downgraded or upgraded by S&P and Moody's.

[2] Capitalized lease obligation and current maturities relate to a finance lease in Brunei, which is classified as held for sale as of December 31, 2019 (see Note E).

The amount of long-term debt repayable over each of the next five years and thereafter are as follows: nil in 2020, nil in 2021, $578.7 million in 2022, nil in 2023, $550.0 million in 2024 and $1.70 billion thereafter.

Note I – Asset Retirement Obligations

The asset retirement obligations liabilities (ARO) recognized by the Company at December 31, 2019 and 2018 are related to the estimated costs to dismantle and abandon its producing oil and natural gas properties and related equipment.

A reconciliation of the beginning and ending aggregate carrying amount of the asset retirement obligation for 2019 and 2018 is shown in the following table.

(Thousands of dollars)	**2019**	2018
Balance at beginning of year	$ **800,117**	447,270
Accretion expense	**40,506**	27,119
Liabilities incurred	**14,759**	6,572
Liabilities assumed from acquisitions	**64,810**	359,643
Revisions of previous estimates	**(34,371)**	(20,012)
Liabilities settled	**(25,544)**	(11,510)
Liabilities associated with assets held for sale	**(240)**	—
Changes due to translation of foreign currencies	**5,072**	(8,965)
Balance at end of year	**865,109**	800,117
Current portion of liability at end of year [1]	**(39,315)**	(47,598)
Noncurrent portion of liability at end of year	$ **825,794**	752,519

[1] Included in Other accrued liabilities on the Consolidated Balance Sheet.

The estimation of future ARO is based on a number of assumptions requiring professional judgment. The Company cannot predict the type of revisions to these assumptions that may be required in future periods due to the availability of additional information such as: prices for oil field services, technological changes, governmental requirements and other factors.

Liabilities assumed in 2019, primarily represent obligations assumed as part of the LLOG acquisition. Liabilities assumed in 2018 primarily represent obligations from the MP GOM acquisition. (see Note D).

Note J – Income Taxes

The components of income (loss) from continuing operations before income taxes for each of the three years presented and income tax expense (benefit) attributable thereto were as follows.

(Thousands of dollars)		**2019**	2018	2017
Income (loss) from continuing operations before income taxes				
United States	$	**282,199**	14,907	(299,349)
Foreign		**(78,701)**	28,095	16,465
Total	$	**203,498**	43,002	(282,884)
Income tax expense (benefit)				
U.S. Federal – Current	$	**—**	(9,765)	—
– Deferred		**30,598**	(131,200)	156,065
Total U.S. Federal		**30,598**	(140,965)	156,065
State		**5,139**	3,299	4,230
Foreign – Current		**(17,823)**	61,257	59
– Deferred		**(3,231)**	(49,727)	109,777
Total Foreign		**(21,054)**	11,530	109,836
Total	$	**14,683**	(126,136)	270,131

The following table reconciles income taxes based on the U.S. statutory tax rate to the Company's income tax expense.

(Thousands of dollars)		**2019**	2018	2017
Income tax expense (benefit) based on the U.S. statutory tax rate	$	**42,735**	9,031	(98,868)
Revaluation of deferred tax (U.S. tax reform)		**—**	—	118,004
Alberta tax rate reduction and tax impact of deemed repatriation of foreign invested earnings (U.S. tax reform)		**(17,019)**	(135,700)	156,000
Deferred tax effect on Canadian earnings no longer indefinitely invested		**—**	—	65,000
Foreign income (loss) subject to foreign tax rates different than the U.S.statutory rate		**(1,122)**	5,822	2,032
State income taxes, net of federal benefit		**4,060**	2,607	2,438
U.S. tax benefit on certain foreign upstream investments		**(14,975)**	(14,702)	(32,926)
Increase in deferred tax asset valuation allowance related to other foreign exploration expenditures		**10,927**	3,283	18,601
Tax effect on income attributable to noncontrolling interest		**(21,750)**	(1,753)	—
Other, net		**11,827**	5,276	39,850
Total	$	**14,683**	(126,136)	270,131

The Tax Cuts and Jobs Act

On December 22, 2017, the U.S. enacted into legislation the Tax Cuts and Jobs Act (2017 Tax Act). For the year ended December 31, 2017, the Company recorded a provisional tax expense of $274.0 million directly related to the impacts of the 2017 Tax Act. The charge included the impact of a deemed repatriation of foreign earnings and the re-measurement of deferred tax assets and liabilities. During 2018, the Company completed the accounting for the income tax effects related to the 2017 Tax Act before the end of the measurement period. The Company revised the provisional amount recorded in 2017 and recognized a favorable income tax adjustment of $135.7 million primarily related to the reinstatement of a deferred tax asset for 2017 net operating losses, which in 2017 was assumed utilized against the deemed repatriation. This reinstatement followed April 2, 2018 Internal Revenue Service guidance which allowed the Company to preserve the 2017 tax net operating loss as a carryforward and allowed previously unused foreign tax credits to be credited against all but $26 million of current income tax on the deemed inclusion of foreign earnings. The $26 million tax is further reduced by $16 million of post-2017 foreign tax credits allowed to be carried back as an offset, which results in a net $10.1 million tax on the deemed repatriation. This tax is fully offset by $29.7 million of AMT credit carryforwards to 2017, with half of the $19.6 million remainder expected to be refunded in 2020, and the balance to be refunded or available to offset future U.S. income tax obligations over the next three years.

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2019 and 2018 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	**2019**	2018
Deferred tax assets		
Property and leasehold costs	**$ 233,351**	231,389
Liabilities for dismantlements	**78,361**	88,075
Postretirement and other employee benefits	**125,250**	113,826
Alternative minimum tax	**9,765**	9,765
U. S. net operating loss	**495,252**	496,629
Other deferred tax assets	**66,795**	19,974
Total gross deferred tax assets	**1,008,774**	959,658
Less valuation allowance	**(103,113)**	(166,991)
Net deferred tax assets	**905,661**	792,667
Deferred tax liabilities		
Deferred tax on undistributed foreign earnings	**(5,000)**	(5,000)
Accumulated depreciation, depletion and amortization	**(938,614)**	(710,384)
Investment in partnership	**(14,250)**	(32,178)
Other deferred tax liabilities	**(25,708)**	(28,802)
Total gross deferred tax liabilities	**(983,572)**	(776,364)
Net deferred tax (liabilities) assets	**$ (77,911)**	16,303

In management's judgment, the net deferred tax assets in the preceding table are more likely than not to be realized based on the consideration of deferred tax liability reversals and future taxable income. The valuation allowance for deferred tax assets relate primarily to tax assets arising in foreign tax jurisdictions that in the judgment of management at the present time are more likely than not to be unrealized. The valuation allowance decreased $63.6 million in 2019 primarily due to the movement of Brunei assets to held for sale. Subsequent reductions of the valuation allowance are expected to be reported as reductions of tax expense assuming no offsetting change in the deferred tax asset.

The Company has an estimated U.S. net operating loss of $2.4 billion at year-end 2019 with a corresponding deferred tax asset of $495.3 million. The Company believes the U.S. net operating loss being carried forward will be utilized in future periods prior to expirations in 2036 and 2037.

Other Information

During 2018 the Company repatriated $1.2 billion to the U.S. and paid $60 million of related Canadian withholding tax. $1.3 billion was identified as not permanently reinvested as of December 31, 2017, with an accompanying $65.0 million liability recorded on the balance sheet as of December 31, 2017. Currently the Company considers $100.0 million of Canada's past foreign earnings not permanently reinvested, with an accompanying $5.0 million liability. At December 31, 2019, $1.4 billion of past foreign earnings are considered permanently reinvested. The Company closely and routinely monitors these reinvestment positions considering underlying facts and circumstances pertinent to our business and the future operation of the company.

Uncertain Income Tax Positions

The financial statement recognition of the benefit for a tax position is dependent upon the benefit being more likely than not to be sustainable upon ultimate settlement. If this threshold is met, the tax benefit is then measured and recognized at the largest amount that is greater than 50% likely of being realized upon ultimate settlement. Liabilities associated with uncertain income tax positions are included in Deferred credits and other liabilities in the Consolidated Balance Sheets. A reconciliation of the beginning and ending amount of the consolidated liability for unrecognized income tax benefits during the three years presented is shown in the following table.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued
Note J – Income Taxes (Contd.)

(Thousands of dollars)		**2019**	2018	2017
Balance at January 1	$	**2,903**	3,437	7,417
Additions for tax positions related to current year		**456**	454	769
Settlements due to lapse of time		**(821)**	(988)	(4,834)
Foreign currency translation effect		**—**	—	85
Balance at December 31	$	**2,538**	2,903	3,437

All additions or settlements to the above liability affect the Company's effective income tax rate in the respective period of change. The Company accounts for any applicable interest and penalties on uncertain tax positions as a component of income tax expense. The Company also had other recorded liabilities as of December 31, 2019, 2018 and 2017 for interest and penalties of $0.1 million, $0.2 million and $0.1 million, respectively, associated with uncertain tax positions. Income tax expense for the years ended December 31, 2019, 2018 and 2017 included net benefits for interest and penalties of $0.1 million, $0.1 million and $0.2 million, respectively, associated with uncertain tax positions.

In 2020, the Company currently expects to add between $0.2 million and $1.0 million to the provision for uncertain tax positions. Although existing liabilities could be reduced by settlement with taxing authorities or lapse due to statute of limitations, the Company believes that the changes in its unrecognized tax benefits due to these events will not have a material impact on the Consolidated Statement of Operations during 2020.

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 December 31, 2019, the earliest years remaining open for audit and/or settlement in the Company's major taxing jurisdictions are as follows: United States – 2016; Canada – 2015; Malaysia – 2012; and United Kingdom – 2017. The Company has retained certain possible liabilities and rights to income tax receivables relating to Malaysia for the years prior to 2019. The Company believes current recorded liabilities are adequate.

Note K – Incentive Plans

Murphy utilizes cash-based and/or share-based incentive awards to supplement normal salaries as compensation for executive management and certain employees. For share-based awards that qualify for equity accounting, costs are recognized as an expense in the Consolidated Statements of Operations using a grant date fair value-based measurement method over the periods that the awards vest. For share-based awards that are required to be accounted for under liability accounting rules, costs are recognized as expense using a fair value-based measurement method over the vesting period, but expense is adjusted as necessary through the date the award value is finally determined. Total expense for liability awards is ultimately adjusted to the final intrinsic value for the award.

In 2018, the Company's shareholders approved replacement of the 2012 Long-Term Incentive Plan (2012 Long-Term Plan) with the 2018 Long-Term Incentive Plan (2018 Long-Term Plan). All awards on or after May 9, 2018 have been made under the 2018 Long-Term Plan.

The Company currently has outstanding incentive awards issued to certain employees under the 2017 Annual Incentive Plan, the 2012 Long-Term Plan and the 2018 Long-Term Plan. The 2017 Annual Incentive 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 Incentive Plan are determined based on the Company's actual financial and operating results as measured against the performance goals established by the Committee.

The 2018 Long-Term Plan and the 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, performance units, performance shares, dividend equivalents and other stock-based incentives. The 2018 Long-Term Plan expires in 2028. A total of 6.75 million shares are issuable during the life of the 2018 Long-Term Plan, with annual grants limited to 1% of Common shares outstanding and total full value share awards (i.e. not options) not to exceed 50% of the total issuable amount; allowed shares not granted in an earlier year may be granted in future years. Based on awards made to date, there are 2.1 million shares available for grant under the 2018 Long-Term Plan at December 31, 2019. In 2018, the Company's shareholders approved the 2018 Stock Plan for Non-Employee Directors (2018 NED Plan) that permits the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company's Non-Employee Directors.

The Company generally expects to issue treasury shares to satisfy future stock option exercises and vesting of restricted stock and restricted stock units.

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

(Thousands of dollars)	**2019**	2018	2017
Compensation charged against income (loss) before income tax benefit	**$ 50,170**	34,467	40,365
Related income tax benefit recognized in income	**7,389**	4,383	5,017

As of December 31, 2019, there were $50.4 million in compensation costs to be expensed over approximately the next five years related to unvested share-based compensation arrangements granted by the Company. Employees receive net shares, after applicable withholding obligations, upon each stock option exercise and restricted stock award. Total income tax benefits realized from tax deductions related to stock option exercises under share-based payment arrangements were immaterial for the years ended December 31, 2019 and 2018. There were no income tax benefits realized in 2017 due to no stock option exercises during that year.

Equity-Settled Awards

STOCK OPTIONS – In 2018, the Company ceased the inclusion of stock options and stock appreciation rights as a part of the long-term incentive compensation mix.

Previously, the Committee fixed the option price of each option granted at no less than fair market value (FMV) on the date of the grant and fixed the option term at no more than seven years from such date. Each option granted to date under the 2012 Long-Term Plan has been nonqualified, with a term of seven years and an option price equal to FMV at date of grant. Under these plans, one-half of each grant is generally exercisable after two years and the remainder after three years. For stock options, the number of shares issued upon exercise is reduced for settlement of applicable statutory income tax withholdings owed by the grantee.

The fair value of each option award is estimated on the date of grant using the Black-Scholes pricing model based on the assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's stock and implied volatility on publicly traded at-the-money options on the Company's stock. The Company estimates the expected term of the options granted based on historical option exercise patterns and considers certain groups of employees exhibiting different behavior. The risk-free interest rate for periods within the expected term of the option is based on the U.S. Treasury yield curve in effect at the time of grant.

	2019	2018	2017
Fair value per option grant	**N/A**	N/A	$7.96
Assumptions			
Dividend yield	**N/A**	N/A	3.60%
Expected volatility	**N/A**	N/A	41.00%
Risk-free interest rate	**N/A**	N/A	1.97%
Expected life	**N/A**	N/A	5.30 years

Table of Contents

Note K – Incentive Plans (Contd.)

Changes in stock options outstanding during the last three years are presented in the following table.

	Number of Shares		Average Exercise Price
Outstanding at December 31, 2016	5,757,435	$	48.46
Granted at FMV	603,000		28.51
Exercised	—		—
Forfeited	(1,459,166)		49.34
Outstanding at December 31, 2017	4,901,269		45.74
Granted at FMV	—		—
Exercised	(72,000)		17.57
Forfeited	(834,674)		53.36
Outstanding at December 31, 2018	3,994,595		44.66
Granted at FMV	**—**		—
Exercised	**(57,500)**		**17.57**
Forfeited	**(1,016,685)**		**48.29**
Outstanding at December 31, 2019	**2,920,410**		**43.93**
Exercisable at December 31, 2016	3,830,535	$	53.80
Exercisable at December 31, 2017	3,197,269		54.22
Exercisable at December 31, 2018	3,182,345		49.10
Exercisable at December 31, 2019	**2,694,410**		**43.51**

Additional information about stock options outstanding at December 31, 2019 is shown below.

	Options Outstanding				Options Exercisable			
Range of Exercise Prices per Option	No. of Options	Avg. Life Remaining in Years		Aggregate Intrinsic Value	No. of Options	Avg. Life Remaining in Years		Aggregate Intrinsic Value
$17.00 to $30.99	1,033,000	3.5	$	5,365,535	807,000	3.4	$	5,365,535
$31.00 to $50.99	730,000	2.1		—	730,000	2.1		—
$51.00 to $65.00	1,157,410	0.5		—	1,157,410	0.5		—
	2,920,410	2.0	**$**	**5,365,535**	**2,694,410**	1.8	**$**	**5,365,535**

The total intrinsic value of options exercised during 2019 was $0.5 million. There were no options exercised in 2017 as all awards either had no intrinsic value or were not vested. Intrinsic value is the excess of the market price of stock at date of exercise over the exercise price received by the Company upon exercise. Aggregate intrinsic value is nil when the exercise price of the stock option exceeds the market price of the Company’s common stock.

PERFORMANCE-BASED RESTRICTED STOCK UNITS – Performance-based restricted stock units (PSUs) to be settled in Common shares were granted in 2019 under the 2018 Long-Term Plan and in 2018 and 2017 under the 2012 Long-Term Plan. Each grant will vest if the Company achieves specific performance objectives at the end of the designated performance period. Additional shares may be awarded if performance objectives are exceeded. If performance goals are not met, PSUs will not vest, but recognized compensation cost associated with the stock award would not be reversed. For PSUs, the performance conditions are based on the Company’s total shareholder return over the performance period compared to an industry peer group of companies. During the performance period, PSUs are subject to transfer restrictions and are subject to forfeiture if a grantee terminates for reasons other than retirement, disability or death. Termination for these three reasons will lead to a pro rata award of amounts earned. No dividends are paid nor do voting rights exist on awards of PSUs prior to their settlement.

Note K – Incentive Plans (Contd.)

Changes in PSUs outstanding for each of the last three years are presented in the following table.

(Number of stock units)	**2019**	2018	2017
Outstanding at beginning of year	**1,660,417**	1,187,921	992,573
Granted	**957,600**	905,500	560,000
Vested and issued	**(331,917)**	(311,866)	(272,725)
Forfeited	**(156,367)**	(121,138)	(91,927)
Outstanding at end of year	**2,129,733**	1,660,417	1,187,921

The fair value of the equity-settled performance-based awards granted in each year was estimated on the date of grant using a Monte Carlo valuation model. Expected volatility was based on daily historical volatility of the Company's stock price compared to a peer group average over a three-year period. The risk-free interest rate is based on the yield curve of three-year U.S. Treasury bonds and the stock beta was calculated using three years of historical averages of daily stock data for Murphy and the peer group. The assumptions used in the valuation of the performance awards granted in 2019, 2018 and 2017 are presented in the following table.

	2019	2018	2017
Fair value per share at grant date	**$28.09**	$22.99 - $30.56	$24.10 – $28.28
Assumptions			
Expected volatility	**46.00%**	48.00%	47.00%
Risk-free interest rate	**2.50%**	2.30%	1.46%
Stock beta	**1.037**	1.103	1.058
Expected life	**3.0 years**	3.0 years	3.0 years

TIME-BASED RESTRICTED STOCK UNITS – Time-based restricted stock units (RSUs) have been granted to the Company's Non-Employee Directors (NED) under the 2013 NED Plan and 2018 NED Plan and to certain employees under the 2012 Long-Term Plan and 2018 Long-Term Plan. These awards vest on the third anniversary of the date of grant. The fair value of these awards was estimated based on the market value of the Company's stock on the date of grant, which were $21.68 to $28.16 per share in 2019, $25.69 to $28.43 per share in 2018, and $28.51 to $28.84 per share in 2017.

Changes in RSUs outstanding for each of the last three years are presented in the following table.

(Number of share units)	**2019**	2018	2017
Outstanding at beginning of year	**1,538,854**	1,035,980	923,282
Granted	**409,692**	823,803	419,720
Vested and issued	**(275,738)**	(233,456)	(217,633)
Forfeited	**(137,728)**	(87,473)	(89,389)
Outstanding at end of year	**1,535,080**	1,538,854	1,035,980

Cash-Settled Awards

The Company has granted stock-based incentive awards to be settled in cash to certain employees in the form of Stock Appreciation Rights (SARs), Performance-based restricted stock units (CPSUs), Time-based restricted stock units (CRSUs) and Phantom units.

SAR awards have terms similar to stock options. CPSU terms are similar to other performance-based restricted stock awards (PSUs). CRSUs generally settle on the third anniversary of the date of grant. Phantom units generally settle three to five years from date of grant. Each award granted is settled, net of applicable income tax withholdings, in cash rather than with Common shares. Total expense recorded in the Consolidated Statements of Operations for all cash-settled stock-based awards was $16.9 million in 2019, $6.5 million in 2018 and $12.9 million in 2017.

The Committee also administers the Company's incentive compensation plans, which provide for annual or periodic cash awards to officers, directors and certain other employees. These cash awards are generally determinable based on the Company achieving specific financial and/or operational objectives. Compensation expense of $34.1 million, $30.0 million and $30.5 million was recorded in 2019, 2018 and 2017, respectively, for these plans.

Note L – Employee and Retiree Benefit Plans

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

Upon the disposal of Murphy's former U.K. downstream assets, the Company retained all vested defined benefit pension obligations associated with former employees of this business. No additional benefits will accrue to these former U.K. employees under the Company's retirement plan after the date of their separation from Murphy.

GAAP requires the Company to recognize the overfunded or underfunded status of its defined benefit plans as an asset or liability in its consolidated balance sheet and to recognize changes in that funded status between periods through accumulated other comprehensive loss.

The tables that follow provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets for the years ended December 31, 2019 and 2018 and a statement of the funded status as of December 31, 2019 and 2018.

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2019**	2018	**2019**	2018
Change in benefit obligation				
Obligation at January 1	$ **777,645**	881,932	**94,779**	106,276
Service cost	**7,964**	8,994	**1,559**	1,965
Interest cost	**27,835**	26,168	**3,864**	3,427
Participant contributions	**11**	—	**1,930**	2,104
Actuarial loss (gain)	**103,374**	(57,378)	**10,503**	(13,778)
Medicare Part D subsidy	**—**	—	**234**	325
Exchange rate changes	**7,687**	(12,742)	**30**	(67)
Benefits paid	**(41,247)**	(41,132)	**(4,498)**	(5,473)
Prior Service Cost	**—**	737	**—**	—
Other	**—**	(28,934)	**—**	—
Obligation at December 31	**883,269**	777,645	**108,401**	94,779
Change in plan assets				
Fair value of plan assets at January 1	**487,094**	563,825	**—**	—
Actual return on plan assets	**70,893**	(18,951)	**—**	—
Employer contributions	**25,915**	24,357	**2,333**	3,044
Participant contributions	**11**	—	**1,930**	2,104
Medicare Part D subsidy	**—**	—	**234**	325
Exchange rate changes	**7,328**	(12,071)	**—**	—
Benefits paid	**(41,247)**	(41,132)	**(4,497)**	(5,473)
Other	**(2,510)**	(28,934)	**—**	—
Fair value of plan assets at December 31	**547,484**	487,094	**—**	—
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	**5,353**	11,039	**—**	—
Other accrued liabilities	**(8,810)**	(9,175)	**(5,234)**	(5,101)
Deferred credits and other liabilities	**(332,328)**	(292,415)	**(103,167)**	(89,678)
Fund Status and net plan liability recognized at December 31	$ **(335,785)**	(290,551)	**(108,401)**	(94,779)

At December 31, 2019, amounts included in Accumulated other comprehensive loss (AOCL) in the Consolidated Balance Sheets, before reduction for associated deferred income taxes, which have not been recognized in net periodic benefit expense are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
Net actuarial gain (loss)	$ (269,391)	3,307
Prior service cost	(4,090)	—
	$ (273,481)	3,307

Amounts included in AOCL at December 31, 2019 that are expected to be amortized into net periodic benefit expense during 2020 are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
Net actuarial loss	$ (17,096)	—
Prior service cost	(734)	—
	$ (17,830)	—

The table that follows includes projected benefit obligations, accumulated benefit obligations and fair value of plan assets for plans where the accumulated benefit obligation exceeded the fair value of plan assets.

	Projected Benefit Obligations		Accumulated Benefit Obligations		Fair Value of Plan Assets	
(Thousands of dollars)	**2019**	2018	**2019**	2018	**2019**	2018
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	**$ 688,249**	457,446	**676,177**	447,793	**525,108**	316,543
Unfunded nonqualified and directors' plans where accumulated benefit obligation exceeds fair value of plan assets	**177,999**	158,228	**171,934**	150,586	**—**	—
Unfunded other postretirement plans	**108,401**	94,808	**108,401**	94,808	**—**	—

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2019.

	Pension Benefits			Other Postretirement Benefits		
(Thousands of dollars)	**2019**	2018	2017	**2019**	2018	2017
Service cost	**$ 7,964**	8,994	8,279	**1,559**	1,965	1,601
Interest cost	**27,835**	26,168	27,047	**3,864**	3,427	3,444
Expected return on plan assets	**(25,719)**	(29,236)	(28,941)	**—**	—	—
Amortization of prior service cost (credit)	**964**	1,021	1,026	**—**	(38)	(74)
Recognized actuarial loss	**14,106**	21,893	16,691	**(193)**	—	—
Net periodic benefit expense	**$ 25,150**	28,840	24,102	**5,230**	5,354	4,971

The preceding tables in this note include the following amounts related to foreign benefit plans.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued
Note L – Employee and Retiree Benefit Plans (Contd.)

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2019**	2018	**2019**	2018
Benefit obligation at December 31	**$ 209,923**	173,860	**387**	812
Fair value of plan assets at December 31	**197,965**	170,551	**—**	—
Net plan liabilities recognized	**(11,957)**	3,309	**387**	812
Net periodic benefit expense (benefit)	**(933)**	3,983	**147**	146

The following table provides the weighted-average assumptions used in the measurement of the Company’s benefit obligations at December 31, 2019 and 2018 and net periodic benefit expense for 2019 and 2018 .

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,		Year		Year	
	2019	2018	**2019**	2018	**2019**	2018	**2019**	2018
Discount rate	**3.85%**	4.07%	**3.42%**	3.73%	**3.35%**	3.54%	**4.42%**	4.32%
Expected return on plan assets	**5.05%**	5.37%	**—**	—	**5.05%**	5.37%	**—**	—
Rate of compensation increase	**3.28%**	3.28%	**—**	—	**3.52%**	3.52%	**—**	—

The discount rates used for determining the plan obligations and expense are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Expected compensation increases are based on anticipated future averages for the Company.

Benefit payments, reflecting expected future service as appropriate, which are expected to be paid in future years from the assets of the plans or by the Company are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
2020	$ 42,399	5,233
2021	43,500	5,360
2022	44,824	5,428
2023	44,850	5,421
2024	45,557	5,505
2025-2030	233,751	27,847

For purposes of measuring postretirement benefit obligations at December 31, 2019, the future annual rates of increase in the cost of health care were assumed to be 6.5% for 2019 decreasing each year to an ultimate rate of 4.5% in 2038 and thereafter.

Assumed health care cost trend rates have a significant effect on the expense and obligation reported for the postretirement benefit plan. A one percent change in assumed health care cost trend rates would have the following effects.

(Thousands of dollars)	1% Increase	1% Decrease
Effect on total service and interest cost components of net periodic postretirement benefit expense for the year ended December 31	$ 930	(737)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31	15,257	(12,291)

During 2019, the Company made contributions of $25.7 million to its domestic defined benefit pension plans, $0.2 million to its foreign defined benefit pension plans and $2.3 million to its domestic postretirement benefits plan. During 2020, Company currently expects to make contributions of $30.6 million to its domestic defined benefit pension plans, $0.6 million to its foreign defined benefit pension plans and $5.2 million to its domestic postretirement benefits plan.

Plan Investments – Murphy Oil Corporation maintains an Investment Policy Statement (Statement) that establishes investment standards related to its funded domestic qualified retirement plan. The Statement specifies that all assets will be held in a Trust sponsored by the Company, which is administrated by a trustee appointed by the Investment Committee (Committee). Members of the Committee are appointed by the Chief Executive Officer of Murphy. The Committee hires Investment Managers to invest trust assets within the guidelines established by the Committee as allowed by the Statement. The investment goals call for a portfolio of assets consisting of equity, fixed income and cash equivalent securities. The primary consideration for investments is the preservation of capital, and investment growth should exceed the rate of inflation. The Committee has directed the asset investment advisors of its benefit plans to maintain a portfolio consisting of both equity and fixed income securities. The Company believes that over time a balanced to slightly heavier weighting of the portfolio in equity securities compared to fixed income securities represents the most appropriate long-term mix for future investment return on assets held by domestic plans.

Generally, no more than 10% of an Investment Manager's portfolio is to be held in equity securities of any one issuer, and equity securities should have a minimum market capitalization of $100.0 million. Equities held in the trust should be listed on the New York or American Stock Exchanges, principal U.S. regional exchanges, major foreign exchanges or quoted in significant over-the-counter markets. Equity or fixed income securities issued by the Company may not be held in the trust. Fixed income securities include maturities greater than one year to maturity. The fixed income portfolio should not exceed an average maturity of 11 years. The portfolio may include investment grade corporate bonds, issues of the U.S. government, its agencies and government sponsored entities, government agency issued collateralized mortgage backed securities, agency issued mortgage backed securities, municipal bonds, asset backed securities, commercial mortgage backed securities and international and emerging markets bond funds. The Committee routinely reviews the investment performance of Investment Managers.

For the U.K. retirement plan, trustees have been appointed by the wholly-owned subsidiary that sponsors the plan for U.K. employees. The trustees have hired Hewitt Risk Management Services Limited (Manager) as fiduciary investment manager of the plan's assets. The trustees have adopted a de-risking strategy which permits the Manager discretion to vary the investment allocation as needed to meet a target return. The target return is reduced over time as pre-determined funding level triggers are met in proportion to pension liability changes. As of December 31, 2019, one of seven funding level triggers have been met which led to a reduction in growth assets to more low-risk assets. The plan primarily invests in two funds, the Delegated Growth Fund DGF and the Delegated Liability Fund DLF. The DGF is diversified by style, strategy and asset class by investing with underlying funds that may include equity funds, fixed income funds, debt funds, currency funds, hedge funds, fund of hedge funds and other collective investment schemes covering a broad range of asset classes and strategies. The DLF aims to provide returns in line with the liabilities of typical pension plans on an exposure basis in the relevant tenures and instruments (long/short, real/nominal). The DLF also holds cash as collateral for the leveraged positions along with small working cash balances to facilitate daily management of payments and receipts within the plan. The trustee routinely reviews the investment performance of the plan.

For the Canadian retirement plan, the wholly-owned subsidiary that sponsors the plan has a Statement of Investment Policies and Procedures (Policy) applicable to the plan assets. A pension committee appointed by the board of directors of the subsidiary oversees the plan, selects the investment advisors and routinely reviews performance of the asset portfolio. The Policy permits assets to be invested in various Canadian and foreign equity securities, various fixed income securities, real estate, natural resource properties or participation rights and cash. The objective for plan investments is to achieve a total rate of return equal to the long-term interest rate assumption used for the going-concern actuarial funding valuation.

The following table provides the asset allocation of each plan on December 31, 2019.

	Allocation of Plan Assets					
	Domestic Plan		Canadian Plan		U.K. Plan	
	Target Allocation	Allocation at **December 31, 2019**	Target Allocation	Allocation at **December 31, 2019**	Target Allocation	Allocation at **December 31, 2019**
Equity securities	40-70%	**54.0%**	28-38%	**34.5%**	N/A	**59.2%**
Fixed income securities	25-60%	**27.8%**	60-70%	**63.5%**	N/A	**18.4%**
Alternatives	0-20%	**16.9%**	—%	**—%**	N/A	**20.2%**
Cash and equivalents	0-15%	**1.3%**	0-10%	**2.0%**	N/A	**2.2%**

The weighted average asset allocation for the Company's funded pension benefit plans at December 31, 2019 and 2018 are presented in the following table.

	December 31,	
	2019	2018
Equity securities	**54.9%**	56.0%
Fixed income securities	**26.2**	42.2
Alternatives	**17.3**	—
Cash equivalents	**1.6**	1.8
	100.0%	100.0%

The Company's weighted average expected return on plan assets was 5.51% in 2019 and the return was determined based on an assessment of actual long-term historical returns and expected future returns for a portfolio with investment characteristics similar to that maintained by the plans. The 5.51% expected return was based on an expected average future equity securities return of 6.30% and a fixed income securities return of 3.95% and is net of average expected investment expenses of 0.60%. Over the last 10 years, the return on funded retirement plan assets has averaged 7.56%.

At December 31, 2019, the fair value measurements of retirement plan assets within the fair value hierarchy are included in the table that follows.

		Fair Value Measurements Using		
(Thousands of dollars)	**Fair Value at December 31, 2019**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Domestic Plans				
Equity securities:				
U.S. core equity	**$ 63,169**	**63,169**	**—**	**—**
U.S. small/midcap	**26,062**	**26,062**	**—**	**—**
Hedged funds and other alternative strategies	**58,864**	**—**	**—**	**58,864**
International commingled trust fund	**73,783**	**924**	**55,798**	**17,061**
Emerging market commingled equity fund	**25,911**	**8,011**	**17,900**	**—**
Fixed income securities:				
U.S. fixed income	**88,525**	**—**	**88,525**	**—**
International commingled trust fund	**8,720**	**—**	**8,720**	**—**
Cash and equivalents	**4,485**	**4,485**	**—**	**—**
Total Domestic Plans	**349,519**	**102,651**	**170,943**	**75,925**
Foreign Plans				
Equity securities funds	**68,878**	**—**	**68,840**	**—**
Fixed income securities funds	**46,582**	**—**	**46,390**	**—**
Diversified pooled fund	**42,582**	**—**	**42,582**	**—**
Other	**35,661**	**—**	**—**	**35,661**
Cash and equivalents	**4,262**	**—**	**4,256**	**—**
Total Foreign Plans	**197,965**	**—**	**162,068**	**35,661**
Total	**$ 547,484**	**102,651**	**333,011**	**111,586**

At December 31, 2018, the fair value measurements of retirement plan assets within the fair value hierarchy are included in the table that follows.

		Fair Value Measurements Using		
(Thousands of dollars)	Fair Value at December 31, 2018	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Plans				
Equity securities:				
U.S. core equity	$ 62,105	62,105	—	—
U.S. small/midcap	19,436	19,436	—	—
Hedged funds and other alternative strategies	45,844	—	10,789	35,055
International commingled trust fund	63,089	—	63,089	—
Emerging market commingled equity fund	15,355	—	15,355	—
Fixed income securities:				
U.S. fixed income	87,526	—	87,526	—
International commingled trust fund	13,274	—	13,274	—
Emerging market mutual fund	4,570	—	4,570	—
Cash and equivalents	5,344	5,344	—	—
Total Domestic Plans	316,543	86,885	194,603	35,055
Foreign Plans				
Equity securities funds	67,165	—	67,165	—
Fixed income securities funds	89,417	—	89,417	—
Diversified pooled fund	10,762	—	10,762	—
Cash and equivalents	3,207	—	3,207	—
Total Foreign Plans	170,551	—	170,551	—
Total	$ 487,094	86,885	365,154	35,055

The definition of levels within the fair value hierarchy in the tables above is included in Note Q – Assets and Liabilities Measured at Fair Value .

For domestic plans, U.S. core and small/midcap equity securities are valued based on daily market prices as quoted on national stock exchanges or in the over-the-counter market. Hedge funds and other alternative strategies funds consist of three investments. One of these investments is valued based on daily market prices as quoted on national stock exchanges, another investment is valued monthly based on net asset value and permits withdrawals semi-annually after a 90-day notice, and the third investment is also valued monthly based on net asset values and has a two-year lock-up period and a 95-day notice following the lock-up period. International equities held in a commingled trust are valued monthly based on prices as quoted on various international stock exchanges. The emerging market commingled equity fund is valued monthly based on net asset value. These commingled equity funds can be withdrawn monthly and have a 10-day notice period. U.S. fixed income securities are valued daily based on bids for the same or similar securities or using net asset values. International fixed income securities held in a commingled trust are valued on a monthly basis using net asset values. The fixed income emerging market mutual fund is valued daily based on net asset value. For foreign plans, the equity securities funds are comprised of U.K. and foreign equity funds valued daily based on fund net asset values. Fixed income securities funds are U.K. securities valued daily at net asset values. The diversified pooled fund is valued daily at net asset value and contains a combination of Canadian and foreign equity securities, Canadian fixed income securities and cash.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued
Note L – Employee and Retiree Benefit Plans (Contd.)

The effects of fair value measurements using significant unobservable inputs on changes in Level 3 plan assets are outlined below:

(Thousands of dollars)	Hedged Funds and Other Alternative Strategies
Total at December 31, 2017	$ 37,950
Actual return on plan assets:	
Relating to assets held at the reporting date	(2,921)
Total at December 31, 2018	35,029
Actual return on plan assets:	
Relating to assets held at the reporting date	**20,811**
Purchases, sales and settlements	55,746
Total at December 31, 2019	**$ 111,586**

THRIFT PLANS – Most full-time U.S. employees of the Company may participate in thrift or similar savings plans by allotting up to a specified percentage of their base pay. The Company matches contributions at a stated percentage of each employee's allotment based on years of participation in the plans, with a maximum match of 6%. Amounts charged to expense for the Company's match to these plans were $8.4 million in 2019, $5.2 million in 2018 and $7.8 million in 2017.

Note M – Financial Instruments and Risk Management

DERIVATIVE INSTRUMENTS – Murphy often uses derivative instruments to manage certain risks related to commodity prices, foreign currency exchange rates and interest rates. The use of derivative instruments for risk management is covered by operating policies and is closely monitored by the Company's senior management. The Company does not hold any derivatives for speculative purposes, and it does not use derivatives with leveraged or complex features. Derivative instruments are traded primarily with creditworthy major financial institutions or over national exchanges such as the New York Mercantile Exchange (NYMEX). The Company has a risk management control system to monitor commodity price risks and any derivatives obtained to manage a portion of such risks. For accounting purposes, the Company has not designated commodity and foreign currency derivative contracts as hedges, and therefore, it recognizes all gains and losses on these derivative contracts in its Consolidated Statements of Operations. Certain interest rate derivative contracts were accounted for as hedges and the gain or loss associated with recording the fair value of these contracts was deferred in AOCL and amortized to Interest expense over the life of the related liability.

Commodity Purchase Price Risks

The Company is subject to commodity price risk related to crude oil it produces and sells. During the last three years, the Company had West Texas Intermediate (WTI) crude oil price 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 December 31, 2019, the Company had 45,000 barrels per day in WTI crude oil swap financial contracts maturing ratably during 2020 at an average price of $56.42. At December 31, 2018, the Company had no open WTI crude oil swap financial contracts.

At December 31, 2019 and 2018, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

	December 31, 2019		December 31, 2018	
(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**	**$ (33,364)**	Accounts receivable	$ 3,837

For the years ended December 31, 2019, 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)		
(Thousands of dollars)		Year Ended December 31,		
Type of Derivative Contract	**Statement of Operations Locations**	**2019**	2018	2017
Commodity	**Gain (loss) on crude contracts**	**$ (856)**	(41,975)	9,566

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 the year ended December 31, 2019, $6.3 million of the deferred loss on the interest rate swaps was charged to Interest expense in the Consolidated Statements of Operations as a result of normal amortization and the early extinguishment of a portion of the deferred loss related to notes due 2022 (see Note H). During each of the years ended December 31, 2018 and 2017, $3.0 million of the deferred loss was recognized in Interest expense in the Consolidated Statements of Operations. The remaining loss (net of tax) deferred on these matured contracts at December 31, 2019 was $2.9 million, which is recorded, net of income taxes of $0.8 million, in Accumulated other comprehensive loss in the Consolidated Balance Sheets.

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 derivative instruments outstanding as of December 31, 2019 and 2018.

CREDIT RISKS – The Company's primary credit risks are associated with trade accounts receivable, cash equivalents and derivative instruments. Trade receivables arise mainly from sales of oil and natural gas in the U.S., Canada and Malaysia, and cost sharing amounts of operating and capital costs billed to partners for oil and natural gas fields operated by Murphy. The credit history and financial condition of potential customers are reviewed before credit is extended, security is obtained when deemed appropriate based on a potential customer's financial condition, and routine follow-up evaluations are made. The combination of these evaluations and the large number of customers tends to limit the risk of credit concentration to an acceptable level. Cash equivalents are placed with several major financial institutions, which limit the Company's exposure to credit risk. The Company controls credit risk on derivatives through credit approvals and monitoring procedures and believes that such risks are minimal because counterparties to the majority of transactions are major financial institutions.

Note N – Earnings per Share

Net income (loss) was used as the numerator in computing both basic and diluted income per Common share for each of the three years ended December 31, 2019. The following table reconciles the weighted-average shares outstanding used for these computations.

(Weighted-average shares)	**2019**	2018	2017
Basic method	**163,992,427**	172,974,491	172,524,061
Dilutive stock options [1]	**820,001**	1,234,274	—
Diluted method	**164,812,428**	174,208,765	172,524,061

[1] Due to a net loss recognized by the Company for the year ended December 31, 2017, no unvested stock awards were included in the computation of diluted earnings per share because the effect would have been antidilutive.

The following table reflects certain options to purchase shares of common stock that were outstanding during the three years ended December 31, 2019, but were not included in the computation of dilutive earnings per share because the incremental shares from the assumed conversion were antidilutive.

	2019	2018	2017
Antidilutive stock options excluded from diluted shares	**2,974,401**	3,942,296	4,901,269
Weighted average price of these options	**$45.26**	$46.77	$45.74

Note O – Other Financial Information

GAIN FROM FOREIGN CURRENCY TRANSACTIONS – Net gains (losses) from foreign currency transactions, including the effects of foreign currency contracts, included in the Consolidated Statements of Operations were $(6.0) million in 2019, $16.1 million in 2018 and $(82.7) million in 2017.

Noncash operating working capital (increased) decreased during each of the three years ended December 31, 2019 as shown in the following table.

(Thousands of dollars)	2019	2018	2017
Net (increase) decrease in operating working capital, excluding cash and cash equivalents:			
(Increase) decrease in accounts receivable [1]	$ **(232,037)**	(30,212)	(15,462)
(Increase) decrease in inventories	**10,258**	16,794	15,429
(Increase) decrease in prepaid expenses	**4,650**	(10,011)	15,752
Increase (decrease) in accounts payable and accrued liabilities [1]	**196,773**	8,784	70,376
Increase (decrease) in income taxes payable	**3,469**	(1,458)	(7,249)
Net (increase) decrease in noncash operating working capital	$ **(16,887)**	(16,103)	78,846
Supplementary disclosures:			
Cash income taxes paid, net of refunds	$ **(6,645)**	(7,603)	(5,969)
Interest paid, net of amounts capitalized of $1.8 million in 2019 and $0.2 million in 2018	**179,722**	158,071	144,455
Non-cash investing activities:			
Asset retirement costs capitalized [2]	$ **33,874**	346,387	126
(Increase) decrease in capital expenditure accrual	**(73,426)**	9,817	16,325

[1] Excludes receivable/payable balances relating to mark-to-market of crude contracts.

[2] Includes asset retirement obligations assumed as part of the LLOG acquisition of $37.3 million.

Note P – Accumulated Other Comprehensive Loss

The components of Accumulated other comprehensive loss on the Consolidated Balance Sheets at December 31, 2019 and December 31, 2018 and the changes during 2019 and 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)
2017 components of other comprehensive income (loss):				
Before reclassifications to income	(145,022)	(16,839)	(1,815)	(163,676)
Reclassifications to income	—	13,790	2,342	16,132
Net other comprehensive income	(145,022)	(3,049)	527	(147,544)
Balance at December 31, 2018	(419,852)	(182,036)	(7,899)	(609,787)
2018 components of other comprehensive income (loss):				
Before reclassifications to income	**66,600**	**(47,264)**	**—**	**19,336**
Reclassifications to income	**—**	**11,285** [1]	**5,005** [2]	**16,290**
Net other comprehensive income (loss)	**66,600**	**(35,979)**	**5,005**	**35,626**
Balance at December 31, 2019	**$ (353,252)**	**(218,015)**	**(2,894)**	**(574,161)**

[1] Reclassifications before taxes of $14,380 and $17,313 are included in the computation of net periodic benefit expense in 2019 and 2018, respectively. See Note L for additional information. Related income taxes of $3,095 and $3,523 are included in income tax expense in 2019 and 2018, respectively.

[2] Reclassifications before taxes of $6,335 and $2,963 are included in Interest expense in 2019 and 2018. Related income taxes of $1,330 and $622 are included in income tax expense in 2019 and 2018. See Note M for additional information.

Note Q – Assets and Liabilities Measured at Fair Value

Fair Values – Recurring

The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheet. 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 fair value measurements for these assets and liabilities at December 31, 2019 and 2018 are presented in the following table

	December 31, 2019				December 31, 2018			
(Thousands of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:								
Commodity derivative contracts	**$ —**	**—**	**—**	**—**	—	3,837	—	3,837
	$ —	**—**	**—**	**—**	—	3,837	—	3,837
Liabilities:								
Nonqualified employee savings plans	**$ 17,035**	**—**	**—**	**17,035**	13,845	—	—	13,845
Commodity derivative contracts	**—**	**33,364**	**—**	**33,364**	—	—	—	—
Contingent consideration	**—**	**—**	**146,787**	**146,787**	—	—	47,730	47,730
	$ 17,035	**33,364**	**146,787**	**197,186**	13,845	—	47,730	61,575

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 fair value of West Texas Intermediate (WTI) crude oil contracts in 2019 and 2018 was based on active market quotes for WTI crude oil. The income effect of changes in 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 (loss).

The Company's contingent consideration liabilities (with PAI and LLOG, as further described in Note D) are measured at fair value on a recurring basis and are categorized as Level 3 in the fair value hierarchy. The contingent consideration liabilities are valued using a Monte Carlo simulation model, which used the following assumptions as of December 31, 2019: (i) the remaining expected life of 3 years for LLOG and 6 years for PAI, (ii) West Texas Intermediate forward strip pricing with historical volatility of 30.0%, and (iii) a risk-free interest rate of 1.66%. The income effect of changes in the fair value of the contingent consideration is recorded in Other (income) expense 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 December 31, 2019 and 2018.

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2019 and 2018. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, trade accounts payable and accrued expenses, all of which had fair values approximating carrying amounts. The fair value of current and long-term debt was estimated based on rates offered to the Company at that time for debt of the same maturities. The Company has off-balance sheet exposures relating to certain letters of credit. The fair value of these, which represents fees associated with obtaining the instruments, was nominal.

	December 31,			
	2019		2018	
(Thousands of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial assets (liabilities):				
Current and long-term debt	**$ (2,803,381)**	**(3,074,929)**	(3,109,986)	(2,899,912)

Fair Values – Nonrecurring

In 2018, as a result of our assessment of market value and our expected recoverable value of select Midland properties in the U.S., the Company recognized a pretax noncash impairment charge of $20.0 million.

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

The fair value information associated with these impaired properties is presented in the following table

	Year Ended December 31, 2018				
	Fair Value				
(Thousands of dollars)	Level 1	Level 2	Level 3	Net Book Value Prior to Impairment	Total Pretax Impairment
Assets:					
Impaired proved properties					
United States Midland	**$ —**	**—**	**37,690**	**57,690**	**20,000**

Note R – Commitments

The Company has operating, production handling and transportation service agreements for oil and/or natural gas operations in the U.S. and Western Canada. The U.S. Onshore and Gulf of Mexico transportation contracts require minimum monthly payments through 2044, while the Western Canada processing contracts call for minimum monthly payments through 2035. In the U.S. and Western Canada, future required minimum monthly payments for the next five years are $128.7 million in 2020, $154.7 million in 2021, $160.8 million in 2022, $149.7 million in 2023 and $139.8 million in 2024. Under certain circumstances, the Company is required to pay additional amounts depending on the actual hydrocarbon quantities processed under the agreement. Total costs incurred under these service arrangements were $117.7 million in 2019, $52.2 million in 2018, and $53.8 million in 2017.

Commitments for capital expenditures were approximately $574.5 million at December 31, 2019, including $518.0 million for costs to develop deepwater U.S. Gulf of Mexico fields including new fields acquired as part of the MP GOM and LLOG transactions, $25.4 million for work at Eagle Ford Shale. Included in this amount is approximately $379.7 million for approved expenditure for capital projects relating to non-operated interests.

Note S – 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 increases; import and export controls; price controls; currency controls; allocation of supplies of crude oil and petroleum products and other goods; expropriation of property; restrictions and preferences affecting the issuance of oil and natural 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.

ENVIRONMENTAL MATTERS – Murphy and other companies in the oil and natural 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. Murphy USA Inc. has retained any environmental exposure associated with Murphy's former U.S. marketing operations that were spun-off in August 2013. 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.

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.

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

Note T – Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2019 is shown below.

(*Number of shares outstanding*)	**2019**	2018	2017
Beginning of year	**173,058,829**	172,572,873	172,202,177
Stock options exercised [1]	**12,345**	21,200	—
Restricted stock awards [1]	**561,729**	464,756	368,132
Employee stock purchase and thrift plans	**—**	—	2,564
Treasury shares purchased	**(20,697,542)**	—	—
End of year	**152,935,361**	173,058,829	172,572,873

[1] Shares issued upon exercise of stock options and award of restricted stock are less than the amount reflected in Note K due to withholdings for statutory income taxes owed upon issuance of shares.

Note U – Business Segments

Murphy's reportable segments are organized into geographic areas of operations. The Company's exploration and production activity is subdivided into segments for the United States, Canada and all other countries. Each of these segments derives revenues primarily from the sale of crude oil, condensate, natural gas liquids and/or natural gas. The Company's management evaluates segment performance based on income (loss) from operations, excluding interest income and interest expense.

The Company has several customers that purchase a significant portion of its oil and natural gas production. During 2019 sales to Chevron represented approximately 25% and Phillips 66 and affiliated companies accounted for 17% of the Company's total sales revenue. In 2018 and 2017 sales to Phillips 66 and affiliated companies represented approximately 12% and 14%, respectively, of the Company's total sales revenue. Due to the quantity of active oil and natural gas purchasers in the markets where it produces hydrocarbons, the Company does not foresee any difficulty with selling its hydrocarbon production at fair market prices.

The Company completed the sale of its Malaysian assets in 2019. The U.K. and Malaysian operations have been reported as Discontinued operations for all periods presented in these consolidated financial statements. For all years presented, assets and liabilities associated with U.K. refining and marketing operations were reported as held for sale in the Consolidated Balance Sheets. As of December 31, 2019, the assets and liabilities associated with Brunei as also reported as held for sale in the Consolidated Balance Sheet.

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 and other activities, 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, are shown in the tables to reconcile the business segments to consolidated totals. As used in the table on the following page, certain long-lived assets at December 31, exclude investments, noncurrent receivables, deferred tax assets, and other intangible assets.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued
Note U - Business Segments (Contd.)

(Millions of dollars)	Exploration and Production				Corporate and Other	Discontinued Operations	Consolidated Total
	United States [1]	Canada	Other	Total E&P			
Year ended December 31, 2019							
Segment income (loss) - including NCI [1]	**$ 518.4**	**(4.3)**	**(53.5)**	**460.6**	**$ (271.8)**	**1,064.5**	**1,253.3**
Revenues from external customers	**2,367.0**	**447.0**	**11.6**	**2,825.6**	**3.5**	**—**	**2,829.1**
Interest and other income (loss)	**(13.4)**	**(1.5)**	**(0.9)**	**(15.8)**	**(6.7)**	**—**	**(22.5)**
Interest expense, net of capitalization	**—**	**(0.1)**	**(0.4)**	**(0.5)**	**(218.8)**	**—**	**(219.3)**
Income tax expense (benefit)	**115.6**	**(2.9)**	**(12.4)**	**100.3**	**(85.6)**	**—**	**14.7**
Significant noncash charges (credits)							
Depreciation, depletion and amortization	**878.7**	**243.0**	**3.5**	**1,125.2**	**22.6**	**—**	**1,147.8**
Accretion of asset retirement obligations	**34.4**	**6.1**	**—**	**40.5**	**—**	**—**	**40.5**
Amortization of undeveloped leases	**23.1**	**1.3**	**3.6**	**28.0**	**—**	**—**	**28.0**
Deferred and noncurrent income taxes	**111.8**	**14.0**	**(13.4)**	**112.4**	**(83.9)**	**—**	**28.5**
Additions to property, plant, equipment	**2,193.3**	**284.1**	**69.8**	**2,547.2**	**13.6**	**—**	**2,560.8**
Total assets at year-end	**8,043.3**	**2,303.7**	**308.6**	**10,655.6**	**1,046.2**	**16.7**	**11,718.5**
Year ended December 31, 2018							
Segment income (loss) - including NCI [1]	$ 242.9	51.1	(16.6)	277.4	$ (108.2)	250.3	419.5
Revenues from external customers	1,332.7	470.5	22.2	1,825.4	(34.0)	—	1,791.4
Interest and other income (loss)	—	—	—	—	7.8	—	7.8
Interest expense, net of capitalization	—	—	0.2	0.2	(180.6)	—	(180.4)
Income tax expense (benefit)	68.1	14.5	(25.3)	57.3	(183.4)	—	(126.1)
Significant noncash charges (credits)							
Depreciation, depletion and amortization	519.5	232.4	3.5	755.4	20.2	—	775.6
Accretion of asset retirement obligations	19.5	7.6	—	27.1	—	—	27.1
Amortization of undeveloped leases	36.8	0.8	2.5	40.1	—	—	40.1
Deferred and noncurrent income taxes	68.1	16.5	(25.7)	58.9	(242.1)	—	(183.2)
Additions to property, plant, equipment	1,343.5	373.8	15.9	1,733.2	22.7	138.6	1,894.5
Total assets at year-end	6,342.9	1,711.9	188.1	8,242.9	1,118.5	1,691.2	11,052.6
Year ended December 31, 2017							
Segment income (loss)	$ (8.9)	112.5	(37.5)	66.1	$ (619.1)	241.2	(311.8)
Revenues from external customers	944.3	485.5	—	1,429.8	14.2	—	1,444.0
Interest and other income (loss)	—	—	—	—	(78.3)	—	(78.3)
Interest expense, net of capitalization	—	—	—	—	(178.3)	—	(178.3)
Income tax expense (benefit)	(0.8)	44.4	(36.2)	7.4	262.7	—	270.1
Significant noncash charges (credits)							
Depreciation, depletion and amortization	546.1	185.4	3.8	735.3	16.6	—	751.9
Accretion of asset retirement obligations	17.4	7.9	—	25.3	—	—	25.3
Amortization of undeveloped leases	60.2	1.6	—	61.8	—	—	61.8
Deferred and noncurrent income taxes	2.5	55.3	(36.2)	21.6	242.5	—	264.1
Additions to property, plant, equipment	534.8	267.6	37.6	840.0	14.8	16.0	870.8
Total assets at year-end	5,186.2	1,725.8	154.2	7,066.2	1,101.7	1,693.0	9,860.9

[1] 2019 and 2018 include results attributable to a noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued
Note U - Business Segments (Contd.)

Geographic Information	**Certain Long-Lived Assets at December 31**			
(Millions of dollars)	United States	Canada	Other	Total
2019	**$ 8,003.9**	**1,761.2**	**204.6**	**9,969.7**
2018	6,634.3	1,644.6	153.2	8,432.1
2017	5,050.5	1,635.9	141.3	6,827.7

Geographic Information	**Revenues from External Customers for the Year**			
(Millions of dollars)	United States	Canada	Other	**Total**
2019	**$ 2,370.4**	**447.1**	**11.6**	**2,829.1**
2018	1,300.3	468.9	22.2	1,791.4
2017	958.3	485.7	—	1,444.0

Note V – Leases

Nature of Leases

The Company has entered into various operating leases such as a natural gas processing plant, floating production storage and off-take vessels, buildings, marine vessels, vehicles, drilling rigs, pipelines and other oil and gas field equipment. Remaining lease terms range from 1 year to 20 years, some of which may include options to extend leases for multi-year periods and others which include options to terminate the leases within 1 month. Options to extend lease terms are at the Company's discretion. Early lease terminations are a combination of both at Company discretion and mutual agreement between the Company and lessor. Purchase options also exist for certain leases.

Related Expenses

Expenses related to finance and operating leases included in the Consolidated Financial Statements are as follows:

(Thousands of dollars)	**Financial Statement Category**	**Year Ended December 31, 2019**
Operating lease [1,2]	Lease operating expenses	**$ 249,787**
Operating lease [2]	Selling and general expense	**12,325**
Operating lease [2]	Other operating expense	**2,588**
Operating lease [2]	Property, plant and equipment	**133,837**
Operating lease [2]	Asset retirement obligations	**3,024**
Finance lease		
Amortization of asset	Depreciation, depletion and amortization	**420**
Interest on lease liabilities	Interest expense, net	**202**
Sublease income	Other income	**(1,419)**
Net lease expense		**$ 400,764**

[1] For the year ended December 31, 2019, includes variable lease expenses of $28.7 million, primarily related to additional volumes processed at a natural gas processing plant.

[2] For the year ended December 31, 2019, includes $56.3 million in Lease operating expense, $4.3 million in Selling and general expense, $2.6 million in Other operating expense, $102.7 million in Property, plant and equipment, net and $3.0 million in Asset retirement obligations relating to short-term leases due within 12 months. Expenses primarily relate to drilling rigs and other oil and natural gas field equipment.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued
Note V – Leases (Contd.)

Maturity of Lease Liabilities

(Thousands of dollars)	Operating Leases [1]	Finance Leases	Total
2020	$ 124,267	1,069	125,336
2021	74,978	1,069	76,047
2022	56,756	1,069	57,825
2023	54,986	1,069	56,055
2024	50,640	1,069	51,709
Remaining	493,833	4,541	498,374
Total future minimum lease payments	855,460	9,886	865,346
Less imputed interest	(241,850)	(1,941)	(243,791)
Present value of lease liabilities [2]	**$ 613,610**	**7,945**	**621,555**

[1] Excludes $278.7 million of minimum lease payments for leases entered but not yet commenced. These payments relate to an expansion of an existing natural gas processing plant and payments are planned to commence at the end of 2020 for 20 years.

[2] Includes both the current and long-term portion of the lease liabilities. Financing lease pertains to Brunei, which is classified as held for sale on the Consolidated Balance Sheet as of December 31, 2019.

Lease Term and Discount Rate

	December 31, 2019
Weighted average remaining lease term:	
Operating leases	**10 years**
Finance leases	**9 years**
Weighted average discount rate:	
Operating leases	**4.7%**
Finance leases	**4.7%**

Other Information

(Thousands of dollars)	Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	**$ 193,968**
Operating cash flows from finance leases	**408**
Financing cash flows from finance leases	**688**
Right-of-use assets obtained in exchange for lease liabilities:	
Operating leases	**$ 125,026**

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED)

The following unaudited schedules are presented in accordance with required disclosures about Oil and Natural gas Producing Activities to provide users with a common base for preparing estimates of future cash flows and comparing reserves among companies. Additional background information concerning some of the schedules follows:

SCHEDULE 1 – SUMMARY OF TOTAL PROVED EQUIVALENT RESERVES
SCHEDULE 2 – SUMMARY OF PROVED CRUDE OIL RESERVES
SCHEDULE 3 – SUMMARY OF PROVED NATURAL GAS LIQUIDS RESERVES
SCHEDULE 4 – SUMMARY OF PROVED NATURAL GAS RESERVES

Reserves of crude oil, condensate, natural gas liquids and natural gas are estimated by the Company's or independent engineers and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reserve estimates and future cash flows are based on the average market prices for sales of oil and natural gas on the first calendar day of each month during the year. The average prices used for 2019 were $55.69 per barrel for NYMEX crude oil (WTI), and $2.57 per Mcf for natural gas (Henry Hub). The average prices used for 2018 were $65.56 per barrel for NYMEX crude oil (WTI), and $3.10 per Mcf for natural gas (Henry Hub). Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

Murphy's estimations for proved reserves were generated through the integration of available geoscience, engineering, and economic data and commercially available technologies to establish "reasonable certainty" of economic producibility. As defined by the SEC, reasonable certainty of proved reserves describes a high degree of confidence that the quantities will be recovered. In estimating proved reserves, Murphy uses common industry-accepted methods for subsurface evaluations, including performance, volumetric and analog-based studies. Where appropriate, Murphy includes reliable geologic and engineering technology to estimate proved reserves. Reliable geologic and engineering technology is a method or combination of methods that are field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. This integrated approach increases the quality of and confidence in Murphy's proved reserves estimates. The approach was utilized in certain undrilled acreage at distances greater than the directly offsetting development spacing areas and in certain reservoirs developed with the application of improved recovery techniques. Murphy utilized a combination of 3D seismic interpretation, core analysis, wellbore log measurements, well test data, historic production and pressure data and commercially available seismic processing and numerical reservoir simulation programs. Reservoir parameters from analogous reservoirs were used to strengthen the reserves estimates when available.

Production quantities shown are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, volumes consumed for fuel and/or shrinkage from the extraction of natural gas liquids.

All crude oil, natural gas liquid reserves and natural gas reserves are from consolidated subsidiaries (including noncontrolling interest) and proportionately consolidated joint ventures. The Company has no proved reserves attributable to investees accounted for by the equity method.

SCHEDULE 7 – STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND NATURAL GAS RESERVES

GAAP requires calculation of future net cash flows using a 10% annual discount factor, an unweighted average of oil and natural gas prices in effect at the beginning of each month of the year, and year-end costs and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates. On December 22, 2017, the U.S. enacted into legislation the Tax Cuts and Jobs Act (2017 Tax Act); as a result, the company's statutory U.S. tax rate was 21% in 2018 and a decrease from the previous rate of 35% in 2017 and 2016.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future cash flows because prices, costs and governmental policies do not remain static; appropriate discount rates may vary; and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

Schedule 7 also presents the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 2019.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED)

Schedule 1 – Summary of Total Proved Equivalent Reserves Based on Average Prices for 2016 – 2019

	Equivalents			
(Millions of barrels of oil equivalent)	Total	United States	Canada	Malaysia and Other
Proved developed and undeveloped reserves:				
December 31, 2016	684.5	287.4	241.0	156.2
Revisions of previous estimates	(5.6)	(5.4)	4.9	(5.2)
Improved recovery	2.0	—	—	2.0
Extensions and discoveries	71.2	39.6	31.3	0.3
Purchases of properties	5.9	5.9	—	—
Production	(59.8)	(22.5)	(18.1)	(19.2)
December 31, 2017	698.2	304.9	259.2	134.1
Revisions of previous estimates	(21.8)	(14.0)	(18.1)	10.4
Improved recovery	0.9	—	—	0.9
Extensions and discoveries	122.6	60.1	61.8	0.8
Purchases of properties	106.9	98.7	6.9	1.3
Production	(62.8)	(24.0)	(21.1)	(17.7)
December 31, 2018	844.0	425.6	288.6	129.7
Revisions of previous estimates	**28.4**	**(17.9)**	**46.1**	**0.3**
Extensions and discoveries	**73.3**	**62.2**	**11.1**	**—**
Purchases of properties	**76.2**	**76.2**	**—**	**—**
Sales of properties	**(121.5)**	**(0.1)**	**—**	**(121.4)**
Production	**(75.4)**	**(45.9)**	**(21.7)**	**(7.8)**
December 31, 2019 [1]	**825.0**	**500.1**	**324.1**	**0.8**
Proved developed reserves:				
December 31, 2016	343.5	157.8	103.3	82.4
December 31, 2017	346.7	170.9	114.1	61.7
December 31, 2018	430.2	247.0	124.2	59.1
December 31, 2019 [2]	**472.3**	**273.4**	**198.1**	**0.8**
Proved undeveloped reserves:				
December 31, 2016	341.1	129.6	137.7	73.8
December 31, 2017	351.5	134.0	145.1	72.4
December 31, 2018	413.8	178.7	164.5	70.7
December 31, 2019 [3]	**352.7**	**226.7**	**126.0**	**—**

[1] Includes proved reserves of 24.6 MMBOE, consisting of 22.1 MMBBL oil, 0.9 MMBBL NGLs, and 9.5 BCF natural gas attributable to the noncontrolling interest in MP GOM.
[2] Includes proved developed reserves of 19.6 MMBOE, consisting of 17.7 MMBBL oil, 0.7 MMBBL NGLs, and 7.1 BCF natural gas attributable to the noncontrolling interest in MP GOM.
[3] Includes proved undeveloped reserves of 5.0 MMBOE, consisting of 4.4 MMBBL oil, 0.2 MMBBL NGLs, and 2.4 BCF natural gas attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND COSOLIDATED SUBSIDIRIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED) – Continued

Schedule 1 – Summary of Total Proved Equivalent Reserves Based on Average Prices for 2015 – 2018 – Continued

2019 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The positive Canadian equivalents reserves revisions in 2019 resulted from improved performance in the Tupper Montney asset which offset reserves reductions from deferrals of capital expenditures at Kaybob Duvernay. The 2019 negative equivalents revision in the U.S. was primarily attributable to changes in well performance in the Eagle Ford Shale, primarily the Tilden area.

Extensions and discoveries - In 2019, proved equivalent reserves were added in the U.S. for drilling activities in both the Eagle Ford Shale and in Canada at Kaybob Duvernay. Proved equivalent reserves were also added for drilling activities in both the U.S. offshore and Canada offshore.

Purchases and sales of properties - In 2019, the Company acquired deepwater Gulf of Mexico producing assets from LLOG. In addition, the Company acquired incremental ownership in the Chinook field in the Gulf of Mexico and partial ownership in the Jagus East field in Brunei (which is now held for sale). The Company's Malaysia assets were divested in 2019.

2018 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The 2018 negative proved equivalents revision in the U.S. was primarily attributable to revised type curves and the removal of proved undeveloped locations outside the 5-year development window. The negative Canadian equivalent reserves revisions in 2018 resulted from deferrals of capital expenditures of the Kaybob Duvernay as well as locations removed in Hibernia Offshore Canada due to updated operator development plans. The positive revisions for proved equivalent reserves in Malaysia were principally attributable to continued development in Kakap field and improved performance in South Acis field.

Improved recovery - The 2018 Malaysia proved equivalent reserve addition was due to favorable impacts from gas lift activity at the Kikeh field.

Extensions and discoveries - In 2018, proved equivalent reserves were added in the U.S. for drilling activities in the Eagle Ford Shale, and in Canada for drilling activities in the Kaybob Duvernay. Proved equivalent reserves were also added for drilling activities in the U.S. offshore.

Purchases of properties - In 2018, the Company acquired producing assets from PAI, which were contributed to MP GOM, for which Murphy owns 80% of the associated assets and oversees operations. In addition, the Company acquired partial ownership in the Jagus East field in Brunei.

2017 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The 2017 negative proved equivalent reserves revision in the U.S. was primarily attributable to the removal of proved undeveloped locations within the 5-year development window as capital was reallocated to higher performing drilling locations within the Company's Eagle Ford Shale fields, partially offset by improved Eagle Ford Shale costs and performance results in the Gulf of Mexico. The positive Canadian proved equivalent reserves revisions in 2017 resulted from improved performance at Tupper Montney assets in onshore Canada, and offshore Canada fields, Hibernia and Terra Nova. The negative revisions for proved equivalent reserves in Malaysia were principally attributable to the redetermination of Kakap participation that lowered the Company's entitlement, and higher government entitlement under the terms of the respective production sharing contracts due to higher oil prices, offsetting positive performance revisions at the Company's Sarawak projects.

Improved recovery - The 2017 Malaysia proved equivalent reserve addition was primarily due to favorable impacts for waterflood activity at certain Sarawak oil fields.

Extensions and discoveries - In 2017, proved equivalent reserves were added in the U.S. for drilling activities in the Eagle Ford Shale concurrent with the reallocation of capital to higher performing drilling areas moving well locations within the 5-year development window for proved undeveloped reserves, and in Canada for drilling activities in the Montney and Duvernay. Proved equivalent reserves were also added for drilling activities in the U.S. offshore. In Malaysia, proved equivalent reserves were added in Sarawak from field development activities.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED)

Schedule 2 – Summary of Proved Crude Oil Reserves Based on Average Prices for 2016 – 2019

(Millions of barrels)	Total	United States	Canada	Malaysia and Other
Proved developed and undeveloped crude oil reserves:				
December 31, 2016	329.0	214.4	48.9	65.7
Revisions of previous estimates	(6.0)	(4.7)	2.3	(3.6)
Improved recovery	2.0	—	—	2.0
Extensions and discoveries	31.6	27.2	4.4	—
Purchases of properties	4.7	4.7	—	—
Production	(33.2)	(16.9)	(4.1)	(12.2)
December 31, 2017	328.1	224.7	51.5	51.9
Revisions of previous estimates	(15.3)	(15.0)	(8.0)	7.7
Improved recovery	0.8	—	—	0.8
Extensions and discoveries	58.9	42.9	16.0	—
Purchases of properties	93.6	92.3	—	1.3
Production	(33.6)	(18.4)	(4.5)	(10.7)
December 31, 2018	432.5	326.5	55.0	51.0
Revisions of previous estimates	**(31.0)**	**(17.1)**	**(14.0)**	**0.1**
Extensions and discoveries	**58.2**	**49.2**	**9.0**	**—**
Purchases of properties	**56.3**	**56.3**	**—**	**—**
Sales of properties	**(45.8)**	**(0.1)**	**—**	**(45.7)**
Production	**(46.3)**	**(37.0)**	**(4.7)**	**(4.6)**
December 31, 2019 [1]	**423.9**	**377.8**	**45.3**	**0.8**
Proved developed crude oil reserves:				
December 31, 2016	184.9	113.9	19.2	51.8
December 31, 2017	185.5	126.3	21.9	37.3
December 31, 2018	249.3	189.0	23.3	37.0
December 31, 2019 [2]	**230.9**	**205.0**	**25.1**	**0.8**
Proved undeveloped crude oil reserves:				
December 31, 2016	144.1	100.5	29.7	13.9
December 31, 2017	142.6	98.4	29.6	14.6
December 31, 2018	183.2	137.5	31.7	14.0
December 31, 2019 [3]	**193.0**	**172.8**	**20.2**	**—**

[1] Includes total proved reserves of 22.1 MMBO for Total and United States attributable to the noncontrolling interest in MP GOM.
[2] Includes proved developed reserves of 17.7 MMBO for Total and United States attributable to the noncontrolling interest in MP GOM.
[3] Includes proved undeveloped reserves of 4.4 MMBO for Total and United States attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND COSOLIDATED SUBSIDIRIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED) – Continued

Schedule 2 – Summary of Proved Crude Oil Reserves Based on Average Prices for 2015 – 2018 – Continued

2019 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates – The 2019 negative crude oil revision in the U.S. was primarily attributable to changes in well performance in the Eagle Ford Shale, primarily in the Tilden area. The negative Canadian oil reserves revisions in 2019 resulted from deferrals of capital expenditures at Kaybob Duvernay.

Extensions and discoveries – In 2019, proved oil reserves were added in the U.S. for drilling activities both in the Eagle Ford Shale and in Canada at Kaybob Duvernay. Proved oil reserves were also added for drilling activities in both the U.S. offshore and Canada offshore.

Purchases and sales of properties – In 2019, the Company acquired deepwater Gulf of Mexico producing assets from LLOG. In addition, the Company acquired incremental ownership in the Chinook field in the Gulf of Mexico. The Company's Malaysia assets were divested in 2019.

2018 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates – The 2018 negative crude oil revision in the U.S. was primarily attributable to revised type curves and the removal of proved undeveloped locations outside the 5-year development window. The negative Canadian oil reserves revisions in 2018 resulted from deferrals of capital expenditures at Kaybob Duvernay as well as locations removed in Hibernia Offshore Canada due to updated operator development plans. The positive revisions for crude oil reserves in Malaysia were principally attributable to continued development in Kakap field and improved performance in South Acis field.

Improved recovery – The 2018 Malaysia crude oil proved reserve addition was due to favorable impacts from natural gas lift activity at the Kikeh field.

Extensions and discoveries – In 2018, proved oil reserves were added in the U.S. for drilling activities in the Eagle Ford Shale, and in Canada for drilling activities in the Kaybob Duvernay. Proved oil reserves were also added for drilling activities in the U.S. offshore.

Purchases of properties – In 2018, the Company acquired producing assets from PAI, which were contributed to MP GOM, for which Murphy owns 80% of the associated assets and oversees operations. In addition, the Company acquired partial ownership in the Jagus East field in Brunei.

2017 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates – The 2017 negative crude oil revision in the U.S. was primarily attributable to the removal of proved undeveloped locations within the 5-year development window as capital was reallocated to higher performing drilling locations within the Company's Eagle Ford Shale fields, partially offset by improved Eagle Ford Shale costs and performance results in the Gulf of Mexico. The positive Canadian oil reserves revisions in 2017 resulted from improved performance at Tupper Montney assets in onshore Canada, and offshore Canada fields, Hibernia and Terra Nova. The negative revisions for crude oil reserves in Malaysia were principally attributable to the redetermination of Kakap participation that lowered the Company's entitlement, and higher government entitlement under the terms of the respective production sharing contracts due to higher oil prices, offsetting positive performance revisions at the Company's Sarawak projects.

Improved recovery – The 2017 Malaysia crude oil proved reserve addition was primarily due to favorable impacts for waterflood activity at certain Sarawak oil fields.

Extensions and discoveries – In 2017, proved oil reserves were added in the U.S. for drilling activities in the Eagle Ford Shale concurrent with the reallocation of capital to higher performing drilling areas moving well locations within the 5-year development window for proved undeveloped reserves, and in Canada for drilling activities in the Montney and Duvernay. Proved oil reserves were also added for drilling activities in the U.S. offshore.

Purchases of properties – In 2017, the Company acquired greater working interests in two of its operated Gulf of Mexico fields. In U.S. onshore, the Company acquired acreage in the Permian area of west Texas. Additional Eagle Ford Shale acreage was acquired through joint venture agreements with other operators within its core acreage position.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED)

Schedule 3 – Summary of Proved Natural Gas Liquids (NGL) Reserves Based on Average Prices for 2016 – 2019

(Millions of barrels)	Total	United States	Canada	Malaysia and Other
Proved developed and undeveloped NGL reserves:				
December 31, 2016	42.5	36.4	5.6	0.5
Revisions of previous estimates	1.3	2.0	(0.6)	(0.1)
Extensions and discoveries	7.8	7.0	0.8	—
Purchase of properties	0.5	0.5	—	—
Production	(3.2)	(2.9)	(0.2)	(0.1)
December 31, 2017	48.9	43.0	5.6	0.3
Revisions of previous estimates	(6.2)	(5.3)	(1.6)	0.7
Extensions and discoveries	12.0	9.7	2.3	—
Purchases of properties	3.0	3.0	—	—
Production	(3.5)	(2.8)	(0.4)	(0.3)
December 31, 2018	54.2	47.6	5.9	0.7
Revisions of previous estimates	**(5.0)**	**(2.5)**	**(2.5)**	**—**
Extensions and discoveries	**6.8**	**6.4**	**0.4**	**—**
Purchases of properties	**5.2**	**5.2**	**—**	**—**
Sales of properties	**(0.6)**	**—**	**—**	**(0.6)**
Production	**(4.5)**	**(3.9)**	**(0.5)**	**(0.1)**
December 31, 2019 [1]	**56.1**	**52.8**	**3.3**	**—**
Proved developed NGL reserves:				
December 31, 2016	22.2	20.8	0.9	0.5
December 31, 2017	24.6	23.3	1.0	0.3
December 31, 2018	27.3	24.9	1.7	0.7
December 31, 2019 [2]	**28.1**	**26.2**	**1.9**	**—**
Proved undeveloped NGL reserves:				
December 31, 2016	20.3	15.6	4.7	—
December 31, 2017	24.3	19.7	4.6	—
December 31, 2018	26.9	22.7	4.2	—
December 31, 2019 [3]	**28.0**	**26.6**	**1.4**	—

[1] Includes total proved reserves of 0.9 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.
[2] Includes proved developed reserves of 0.7 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.
[3] Includes proved undeveloped reserves of 0.2 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED) – Continued

Schedule 3 – Summary of Proved Natural Gas Liquids (NGL) Reserves Based on Average Prices for 2016 – 2019– Continued

2019 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates – The negative 2019 NGL proved reserves revision in the U.S. was primarily due to midstream elections in the Eagle Ford Shale resulting in lower NGL yields. The negative Canadian NGL reserves revisions in 2019 resulted from deferrals of capital expenditures at Kaybob Duvernay.

Extensions and discoveries – In 2019, proved NGL reserves were added in the U.S. for drilling activities in both the Eagle Ford Shale and in Canada at Kaybob Duvernay area in onshore Canada. Proved NGL reserves were also added for drilling activities in the U.S. offshore.

Purchases and sales of properties – In 2019, the Company acquired deepwater Gulf of Mexico producing assets from LLOG. In addition, the Company acquired incremental ownership in the Chinook field in the Gulf of Mexico. The Company's Malaysia assets were divested in 2019.

2018 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates – The negative 2018 NGL proved reserves revision in the U.S. was primarily in the Company's Eagle Ford Shale fields based on removal of proved undeveloped locations outside the 5-year development window. The negative Canadian NGL reserves revisions in 2018 resulted from deferrals of capital expenditures at Kaybob Duvernay. The positive revisions for NGL reserves in Malaysia were principally attributable to improved performance for natural gas fields offshore Sarawak.

Extensions and discoveries – In 2018, proved NGL reserves were added in the U.S. for drilling activities in the Eagle Ford Shale, and in Canada for drilling activities in the Kaybob Duvernay.

Purchases of properties – In 2018, the Company acquired producing assets from PAI, which were contributed to MP GOM, for which Murphy owns 80% of the associated assets and oversees operations.

2017 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates – The positive 2017 NGL proved reserves revision in the U.S. was primarily in the Company's Eagle Ford Shale fields based on an updated shrinkage ratio of liquids rich natural gas production combined with improved costs, offsetting removal of proved undeveloped locations from within the 5-year development window as capital was reallocated to higher performing drilling locations within the Eagle Ford Shale.

Extensions and discoveries – Proved NGL reserves were added primarily from drilling activities in the Eagle Ford Shale area concurrent with the reallocation of capital to higher performing drilling areas moving well locations within the 5-year development window for proved undeveloped reserves.

Purchase of properties – In U.S., proved NGL reserves were added following the acquisition of acreage in both the Eagle Ford Shale and Permian areas, and increased working interest in two Gulf of Mexico fields.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED)

Schedule 4 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2016 – 2019

(Billions of cubic feet)	Total	United States	Canada	Malaysia and Other
Proved developed and undeveloped natural gas reserves:				
December 31, 2016	1,878.0	219.4	1,118.9	539.7
Revisions of previous estimates	(5.4)	(16.0)	19.4	(8.8)
Extensions and discoveries	190.6	32.2	156.7	1.7
Purchases of properties	4.0	4.0	—	—
Production	(140.1)	(16.3)	(82.6)	(41.2)
December 31, 2017	1,927.1	223.3	1,212.4	491.4
Revisions of previous estimates	(1.8)	37.6	(51.2)	11.8
Improved recovery	0.6	—	—	0.6
Extensions and discoveries	310.3	44.7	261.0	4.6
Purchases of properties	61.7	20.3	41.4	—
Production	(154.3)	(16.9)	(97.2)	(40.2)
December 31, 2018	2,143.6	309.0	1,366.4	468.2
Revisions of previous estimates	**386.5**	**10.3**	**375.3**	**0.9**
Extensions and discoveries	**49.8**	**39.5**	**10.3**	**—**
Purchases of properties	**88.3**	**88.3**	**—**	**—**
Sales of properties	**(450.7)**	**(0.1)**	**—**	**(450.6)**
Production	**(147.8)**	**(30.2)**	**(99.1)**	**(18.5)**
December 31, 2019 [1]	**2,069.7**	**416.8**	**1,652.9**	**—**
Proved developed natural gas reserves:				
December 31, 2016	818.1	138.7	498.9	180.5
December 31, 2017	819.3	127.7	547.0	144.6
December 31, 2018	921.6	198.3	595.0	128.3
December 31, 2019 [2]	**1,279.8**	**253.1**	**1,026.7**	**—**
Proved undeveloped natural gas reserves:				
December 31, 2016	1,059.9	80.7	620.0	359.2
December 31, 2017	1,107.8	95.6	665.5	346.7
December 31, 2018	1,222.0	110.7	771.4	339.9
December 31, 2019 [3]	**789.9**	**163.7**	**626.2**	**—**

[1] Includes total proved reserves of 9.5 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.
[2] Includes proved developed reserves of 7.1 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.
[3] Includes proved undeveloped reserves of 2.4 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED)

Schedule 4 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2016 – 2019

2019 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates – In 2019, the positive natural gas revisions in Canada resulted from improved performance in the Tupper Montney asset and adjustments relating to royalties. The positive revision for natural gas reserves in the Eagle Ford Shale was primarily attributable to producing well performance.

Extensions and discoveries – In 2019, proved natural gas reserves were added in the U.S. for development drilling activities in both the Eagle Ford Shale and in Canada at Tupper Montney and Kaybob Duvernay. Proved natural gas reserves were also added for drilling activities in both the U.S. offshore and Canada offshore.

Purchases and sales of properties – In 2019, the Company acquired deepwater Gulf of Mexico producing assets from LLOG. In addition, the Company acquired incremental ownership in the Chinook field in the Gulf of Mexico. The Company's Malaysia assets were divested in 2019.

2018 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates – In 2018, the U.S. positive natural gas revision was primarily due to drilling within the Eagle Ford Shale. The 2018 negative natural gas revisions in Canada resulted from deferrals of capital expenditures at Kaybob Duvernay partially offset by positive performance revisions in the Tupper Montney asset. The positive revision for natural gas reserves in Malaysia was primarily attributable to positive performance revisions at the Company's Sarawak projects offset somewhat by negative Block H revisions attributable to higher government entitlement under the terms of the respective production sharing contracts due to higher natural gas prices.

Improved recovery – The 2018 Malaysia natural gas proved reserve addition was due to favorable impacts from natural gas lift activity at the Kikeh field.

Extensions and discoveries – In 2018, the U.S. added natural gas reserves primarily for developmental drilling activities in the Eagle Ford Shale. Natural gas reserve additions in Canada were attributable to developmental drilling activities in the Tupper Montney and Kaybob Duvernay areas in onshore Canada. In Malaysia, proved natural gas reserves were added in the Merapuh field in Sarawak from field development activities.

Purchases of properties – In 2018, the Company acquired producing assets from PAI, which were contributed to MP GOM, for which Murphy owns 80% of the associated assets and overseas operations. In addition, the Company acquired acreage in Tupper Montney in onshore Canada.

2017 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates – In the U.S., the negative natural gas revision was primarily due to shutting in a natural gas well located in the Gulf of Mexico due to early water break through, and in the Company's Eagle Ford Shale fields proved undeveloped locations were removed from within the 5-year development window as capital was reallocated to higher performing drilling locations within the Eagle Ford Shale. The negative revision for natural gas reserves in Malaysia was primarily attributable to higher government entitlement under the terms of the respective production sharing contracts due to higher natural gas prices, offsetting positive performance revisions at the Company's Sarawak projects. The 2017 positive natural gas revisions in Canada were attributable to updated well type curves and field performance at the Tupper Montney assets in onshore Canada.

Extensions and discoveries – In 2017, the U.S. added natural gas reserves primarily for developmental drilling activities in the Eagle Ford Shale concurrent with the reallocation of capital to higher performing drilling areas moving well locations within the 5-year development window for proved undeveloped reserves, and field development drilling in the Gulf of Mexico. Natural gas reserve additions in Canada were attributable to developmental drilling activities in the Montney and Kaybob Duvernay areas in onshore Canada. In Malaysia, proved natural gas reserves were added in Sarawak from field development activities.

Purchase of properties – In the U.S., proved natural gas reserves were added following the acquisition of acreage in both the Eagle Ford Shale and Permian areas, and increased working interest in two Gulf of Mexico fields.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED) – Continued

Schedule 5 – Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

(Millions of dollars)	United States	Canada	Malaysia	Other	Total
Year ended December 31, 2019					
Property acquisition costs					
Unproved	**$ 533.8**	**0.2**	**—**	**13.0**	**547.0**
Proved	**733.1**	**—**	**—**	**—**	**733.1**
Total acquisition costs	**1,266.9**	**0.2**	**—**	**13.0**	**1,280.1**
Exploration costs [1]	**44.8**	**6.4**	**—**	**67.4**	**118.6**
Development costs [1]	**979.0**	**281.8**	**—**	**21.6**	**1,282.4**
Total costs incurred	**2,290.7**	**288.4**	**—**	**102.0**	**2,681.1**
Charged to expense					
Geophysical and other costs	**21.6**	**0.5**	**—**	**32.2**	**54.3**
Total charged to expense	**21.6**	**0.5**	**—**	**32.2**	**54.3**
Property additions	**$ 2,269.1**	**287.9**	**—**	**69.8**	**2,626.8**
Year ended December 31, 2018					
Property acquisition costs					
Unproved	$ 2.8	—	—	0.2	3.0
Proved	794.3	—	—	—	794.3
Total acquisition costs	797.1	—	—	0.2	797.3
Exploration costs [1]	88.1	0.6	2.2	35.1	126.0
Development costs [1]	853.7	373.8	145.9	16.6	1,390.0
Total costs incurred	1,738.9	374.4	148.1	51.9	2,313.3
Charged to expense					
Dry hole expense	16.0	—	0.1	4.5	20.6
Geophysical and other costs	13.4	0.6	2.1	31.3	47.4
Total charged to expense	29.4	0.6	2.2	35.8	68.0
Property additions	$ 1,709.5	373.8	145.9	16.1	2,245.3
Year ended December 31, 2017					
Property acquisition costs					
Unproved	$ 50.4	—	—	13.0	63.4
Proved	7.7	—	—	—	7.7
Total acquisition costs	58.1	—	—	13.0	71.1
Exploration costs [1]	13.7	0.6	(8.9)	73.8	79.2
Development costs [1]	508.4	273.8	35.7	1.1	819.0
Total costs incurred	580.2	274.4	26.8	87.9	969.3
Charged to expense					
Dry hole expense	(1.9)	—	0.7	(3.0)	(4.2)
Geophysical and other costs	9.7	0.5	1.7	53.3	65.2
Total charged to expense	7.8	0.5	2.4	50.3	61.0
Property additions	$ 572.4	273.9	24.4	37.6	908.3

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED) – Continued

Schedule 5 – Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

[1] Includes noncash asset retirement costs as follows:

2019						
Exploration costs	**$**	**—**	**—**	**—**	**—**	**—**
Development costs		**75.8**	**3.8**	**—**	**—**	**79.6**
	$	**75.8**	**3.8**	**—**	**—**	**79.6**
2018						
Exploration costs	$	—	—	—	—	—
Development costs		366.0	—	7.3	0.2	373.5
	$	366.0	—	7.3	0.2	373.5
2017						
Exploration costs	$	—	—	—	—	—
Development costs		37.6	6.3	8.4	—	52.3
	$	37.6	6.3	8.4	—	52.3

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED) – Continued

Schedule 6 – Results of Operations for Oil and Natural Gas Producing Activities [1]

(*Millions of dollars*)	United States	Canada	Other	Total
Year ended December 31, 2019				
Revenues				
Crude oil and natural gas liquids sales	**$ 2,285.8**	**287.4**	**11.6**	**2,584.8**
Natural gas sales	**73.9**	**158.4**	**—**	**232.3**
Total oil and natural gas revenues	**2,359.7**	**445.8**	**11.6**	**2,817.1**
Other operating revenues	**7.3**	**1.2**	**—**	**8.5**
Total revenues	**2,367.0**	**447.0**	**11.6**	**2,825.6**
Costs and expenses				
Lease operating expenses	**461.5**	**142.4**	**1.3**	**605.2**
Severance and ad valorem taxes	**46.6**	**1.4**	**—**	**48.0**
Transportation, gathering and processing	**140.8**	**35.5**	**—**	**176.3**
Exploration costs charged to expense	**21.4**	**0.6**	**45.3**	**67.3**
Undeveloped lease amortization	**23.1**	**1.3**	**3.6**	**28.0**
Depreciation, depletion and amortization	**878.7**	**243.0**	**3.5**	**1,125.2**
Accretion of asset retirement obligations	**34.4**	**6.1**	**—**	**40.5**
Selling and general expenses	**74.3**	**30.0**	**22.5**	**126.8**
Other expenses (benefits)	**52.2**	**(6.1)**	**1.3**	**47.4**
Total costs and expenses	**1,733.0**	**454.2**	**77.5**	**2,264.7**
Results of operations before taxes	**634.0**	**(7.2)**	**(65.9)**	**560.9**
Income tax expense (benefit)	**115.6**	**(2.9)**	**(12.4)**	**100.3**
Results of operations	**$ 518.4**	**(4.3)**	**(53.5)**	**460.6**
Year ended December 31, 2018				
Revenues				
Crude oil and natural gas liquids sales	$ 1,277.7	302.8	6.1	1,586.6
Natural gas sales	53.6	166.3	—	219.9
Total oil and natural gas revenues	1,331.3	469.1	6.1	1,806.5
Other operating revenues	1.4	1.4	16.1	18.9
Total revenues	1,332.7	470.5	22.2	1,825.4
Costs and expenses				
Lease operating expenses	230.5	122.6	0.7	353.8
Severance and ad valorem taxes	50.9	1.2	—	52.1
Transportation, gathering and processing	43.1	31.9	—	75.0
Exploration costs charged to expense	29.4	0.6	31.6	61.6
Undeveloped lease amortization	36.8	0.8	2.5	40.1
Depreciation, depletion and amortization	519.5	232.4	3.5	755.4
Accretion of asset retirement obligations	19.5	7.7	—	27.2
Impairment of assets	20.0	—	—	20.0
Selling and general expenses	49.0	26.8	23.5	99.3
Other expenses	23.0	(19.1)	2.3	6.2
Total costs and expenses	1,021.7	404.9	64.1	1,490.7
Results of operations before taxes	311.0	65.6	(41.9)	334.7
Income tax expense (benefit)	68.1	14.5	(25.3)	57.3
Results of operations	$ 242.9	51.1	(16.6)	277.4

[1] Results exclude corporate overhead, interest and discontinued operations. 2019 and 2018 include noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND COSOLIDATED SUBSIDIRIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED) – Continued

Schedule 6 – Results of Operations for Oil and Gas Producing Activities [1] – Continued

(*Millions of dollars*)	United States	Canada	Other	Total
Year ended December 31, 2017				
Revenues				
Crude oil and natural gas liquids sales	$ 903.7	203.7	—	1,107.4
Natural gas sales	37.9	155.1	—	193.0
Total oil and natural gas revenues	941.6	358.8	—	1,300.4
Other operating revenues	2.7	126.7	—	129.4
Total revenues	944.3	485.5	—	1,429.8
Costs and expenses				
Lease operating expenses	198.5	101.1	—	299.6
Severance and ad valorem taxes	42.2	1.5	—	43.7
Exploration costs charged to expense	7.8	0.5	50.3	58.6
Undeveloped lease amortization	60.2	1.6	—	61.8
Depreciation, depletion and amortization	546.1	185.4	3.8	735.3
Accretion of asset retirement obligations	17.4	7.9	—	25.3
Selling and general expenses	61.8	28.3	19.6	109.7
Other expenses	20.0	2.3	73.7	96.0
Total costs and expenses	954.0	328.6	73.7	1,356.3
Results of operations before taxes	(9.7)	156.9	(73.7)	73.5
Income tax expense (benefit)	(0.8)	44.4	(36.2)	7.4
Results of operations	$ (8.9)	112.5	(37.5)	66.1

[1] Results exclude corporate overhead, interest and discontinued operations.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED) – Continued

Schedule 7 – Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves[1]

(*Millions of dollars*)		United States	Canada	Malaysia & Other	Total
December 31, 2019					
Future cash inflows	**$**	**23,565.6**	**4,912.1**	**55.7**	**28,533.4**
Future development costs		**(4,137.8)**	**(723.7)**	**(0.3)**	**(4,861.8)**
Future production costs		**(8,986.2)**	**(2,549.9)**	**(29.9)**	**(11,566.0)**
Future income taxes		**(1,709.3)**	**(414.5)**	**(14.1)**	**(2,137.9)**
Future net cash flows		**8,732.3**	**1,224.0**	**11.4**	**9,967.7**
10% annual discount for estimated timing of cash flows		**(3,633.1)**	**(504.0)**	**(3.0)**	**(4,140.1)**
Standardized measure of discounted future net cash flows	**$**	**5,099.2**	**720.0**	**8.4**	**5,827.6**
December 31, 2018					
Future cash inflows	$	23,473.9	5,437.5	5,511.6	34,423.0
Future development costs		(3,279.1)	(1,362.7)	(517.4)	(5,159.2)
Future production costs		(7,279.5)	(2,693.0)	(2,813.4)	(12,785.9)
Future income taxes		(2,216.5)	(236.4)	(472.0)	(2,924.9)
Future net cash flows		10,698.8	1,145.4	1,708.8	13,553.0
10% annual discount for estimated timing of cash flows		(4,295.4)	(531.4)	(446.3)	(5,273.1)
Standardized measure of discounted future net cash flows	$	6,403.4	614.0	1,262.5	8,279.9
December 31, 2017					
Future cash inflows	$	12,885.8	4,714.3	4,392.0	21,992.1
Future development costs		(2,079.5)	(1,081.7)	(632.3)	(3,793.5)
Future production costs		(4,765.3)	(2,507.4)	(2,305.0)	(9,577.7)
Future income taxes		(893.7)	(161.1)	(232.2)	(1,287.0)
Future net cash flows		5,147.3	964.1	1,222.5	7,333.9
10% annual discount for estimated timing of cash flows		(2,698.2)	(394.6)	(318.2)	(3,411.0)
Standardized measure of discounted future net cash flows	$	2,449.1	569.5	904.3	3,922.9

[1] 2019 and 2018 include noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND COSOLIDATED SUBSIDIRIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED) – Continued

Schedule 7 – Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves – Continued [1]

Following are the principal sources of change in the standardized measure of discounted future net cash flows for the years shown.

(Millions of dollars)	**2019**	2018	2017
Net changes in prices and production costs [2]	**(2,993.9)**	2,972.6	2,428.4
Net changes in development costs	**(675.7)**	(1,891.1)	(724.4)
Sales and transfers of oil and natural gas produced, net of production costs	**(2,163.8)**	(1,978.6)	(1,576.0)
Net change due to extensions and discoveries	**1,221.9**	1,930.3	807.9
Net change due to purchases and sales of proved reserves	**(628.1)**	3,152.4	85.9
Development costs incurred	**1,282.4**	1,017.3	802.7
Accretion of discount	**1,002.0**	469.5	270.9
Revisions of previous quantity estimates	**(71.2)**	(347.8)	(109.5)
Net change in income taxes	**574.1**	(967.6)	(643.0)
Net increase (decrease)	**(2,452.3)**	4,357.0	1,342.9
Standardized measure at January 1	**8,279.9**	3,922.9	2,580.0
Standardized measure at December 31	**5,827.6**	8,279.9	3,922.9

[1] 2019 and 2018 include noncontrolling interest in MP GOM.
[2] The average prices used for 2019 were $55.69 per barrel for NYMEX crude oil (WTI), and $2.57 per Mcf for natural gas (Henry Hub). The average prices used for 2018 were $65.56 per barrel for NYMEX crude oil (WTI), and $3.10 per Mcf for natural gas (Henry Hub).

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL GAS INFORMATION (UNAUDITED) – Continued

Schedule 8 – Capitalized Costs Relating to Oil and Natural Gas Producing Activities

(*Millions of dollars*)	United States	Canada	Other	Total
December 31, 2019				
Unproved oil and natural gas properties	**$ 1,116.6**	**243.7**	**210.4**	**1,570.7**
Proved oil and natural gas properties	**13,292.6**	**4,176.7**	**21.1**	**17,490.4**
Gross capitalized costs	**14,409.2**	**4,420.4**	**231.5**	**19,061.1**
Accumulated depreciation, depletion and amortization				
Unproved oil and natural gas properties	**(136.4)**	**(225.4)**	**(25.9)**	**(387.7)**
Proved oil and natural gas properties	**(6,298.9)**	**(2,438.6)**	**(2.4)**	**(8,739.9)**
Net capitalized costs	**$ 7,973.9**	**1,756.4**	**203.2**	**9,933.5**
December 31, 2018				
Unproved oil and natural gas properties	$ 394.2	250.0	176.9	821.1
Proved oil and natural gas properties	11,678.3	3,693.0	—	15,371.3
Gross capitalized costs	12,072.5	3,943.0	176.9	16,192.4
Accumulated depreciation, depletion and amortization				
Unproved oil and natural gas properties	(129.3)	(213.5)	(25.4)	(368.2)
Proved oil and natural gas properties	(5,433.7)	(2,088.8)	—	(7,522.5)
Net capitalized costs	$ 6,509.5	1,640.7	151.5	8,301.7

Note: Unproved oil and natural gas properties above include costs and associated accumulated amortization of properties that do not have proved reserves; these costs include mineral interests, uncompleted exploratory wells, and exploratory wells capitalized pending further evaluation.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL QUARTERLY INFORMATION (UNAUDITED)

(*Millions of dollars except per share amounts*)		First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year ended December 31, 2019						
Revenue from contracts with customers	**$**	**629.4**	**680.4**	**750.3**	**757.0**	**2,817.1**
Income (loss) from continuing operations before income taxes		**33.7**	**107.9**	**177.1**	**(115.3)**	**203.5**
Income (loss) from continuing operations		**22.9**	**98.8**	**158.3**	**(91.3)**	**188.8**
Net income (loss) including noncontrolling interest		**72.8**	**123.2**	**1,111.7**	**(54.4)**	**1,253.3**
Net income (loss) attributable to Murphy		**40.2**	**92.3**	**1,089.0**	**(71.7)**	**1,149.7**
Income (loss) from continuing operations per Common share						
Basic		**(0.06)**	**0.40**	**0.85**	**(0.71)**	**0.52**
Diluted		**(0.06)**	**0.40**	**0.84**	**(0.70)**	**0.52**
Net income (loss) per Common share						
Basic		**0.23**	**0.55**	**6.79**	**(0.71)**	**7.01**
Diluted		**0.23**	**0.54**	**6.76**	**(0.47)**	**6.98**
Cash dividend per Common share		**0.25**	**0.25**	**0.25**	**0.25**	**1.00**
Year ended December 31, 2018						
Revenue from contracts with customers	$	411.9	443.0	475.5	476.1	1,806.5
Income (loss) from continuing operations before income taxes		(21.1)	(22.6)	74.0	12.7	43.0
Income (loss) from continuing operations		90.6	(25.2)	56.1	47.6	169.1
Net income including noncontrolling interest		168.3	45.5	93.9	111.8	419.5
Net income attributable to Murphy		168.3	45.5	93.9	103.4	411.1
Income (loss) from continuing operations per Common share						
Basic		0.52	(0.14)	0.32	0.23	0.92
Diluted		0.52	(0.15)	0.32	0.22	0.92
Net income (loss) per Common share						
Basic		0.97	0.27	0.54	0.60	2.38
Diluted		0.96	0.25	0.54	0.59	2.36
Cash dividend per Common share		0.25	0.25	0.25	0.25	1.00

Includes noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SCHEDULE II - VALUATION ACCOUNTS AND RESERVES

(*Millions of dollars*)	Balance at January 1	Charged to Expense	Deductions	Other [1]	Balance at December 31
2019					
Deducted from asset accounts:					
Allowance for doubtful accounts	**$ 1.6**	**—**	**—**	**—**	**1.6**
Deferred tax asset valuation allowance	**166.9**	**10.9**	**—**	**(74.7)**	**103.1**
2018					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 1.6	—	—	—	1.6
Deferred tax asset valuation allowance	407.3	3.3	—	(243.7)	166.9
2017					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 1.6	—	—	—	1.6
Deferred tax asset valuation allowance	236.4	18.6	—	152.3	407.3

[1] The amounts in 2019 and 2018 for deferred tax asset valuation allowance are primarily associated with utilization of foreign tax credit carryforwards. The amount in 2017 for deferred tax asset valuation are primarily associated with an increase in foreign tax credit carryforwards.

GLOSSARY

3D seismic

three-dimensional images created by bouncing sound waves off underground rock formations that are used to determine the best places to drill for hydrocarbons

deepwater

offshore location in greater than 1,000 feet of water

downstream

refining and marketing operations

dry hole

an unsuccessful exploration well that is plugged and abandoned, with associated costs written off to expense

exploratory

wildcat and delineation, e.g., exploratory wells

hydrocarbons

organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products

operator

the company serving as the manager and often the decision-maker of a drilling or production project

production sharing contract

agreement between extracting company(ies) and a host country regarding each party's share of production after stipulated exploratory and development costs are recovered

unitization

combining of multiple mineral or leasehold interests to be able to produce from a common reservoir

upstream

oil and natural gas exploration and production operations, including synthetic oil operation

working interest

right to drill and produce oil and gas on the leased acreage, as well as the obligation to pay costs

ABBREVIATIONS

ARO - Asset Retirement Obligation

ASU - Accounting Standards Update

BCF - Billion cubic feet

BOED - Barrel of oil equivalent per day

FASB - Financial Accounting Standards Board

FLNG - Floating Liquified Natural Gas

GAAP - U.S. Generally Accepted Accounting Principles

GK - Gumusut/Kakap

MCF - Thousand cubic feet

MMBOE - Million barrels of oil equivalent

MMCF - Million cubic feet

MMCFD – Million cubic feet per day

MOCL - Murphy Oil Company Ltd.

NCI - Noncontrolling interest

NYMEX - New York Mercantile Exchange

OSHA - Occupational Safety and Health Act

PAI – Petrobras Americas Inc., a subsidiary of Petróleo Brasileiro S.A.

QRE - Qualified Reserve Estimators

SEC - U.S. Securities and Exchange Commission

UFA - Unitization Framework Agreement

WTI - West Texas Intermediate

Exhibit 4.9

DESCRIPTION OF SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

The following summary describes the securities of Murphy Oil Corporation (the "Company") registered pursuant to Section 12 of the Securities Exchange Act of 1934, as amended. For purposes of this description, references to the "Company," "Murphy Oil," "we," "our" and "us" refer only to the Company and not to its subsidiaries.

DESCRIPTION OF COMMON STOCK

The following description of our capital stock is based upon our certificate of incorporation ("Certificate of Incorporation"), our bylaws ("Bylaws") and applicable provisions of law. We have summarized certain portions of the Certificate of Incorporation and Bylaws below. The summary is not complete. The Certificate of Incorporation and Bylaws are filed as exhibits to our Annual Report on Form 10-K for the year ended December 31, 2019. You should read the Certificate of Incorporation and Bylaws for the provisions that are important to you.

Certain provisions of the Delaware General Corporation Law ("DGCL"), the Certificate of Incorporation and the Bylaws summarized in the following paragraphs may have an anti-takeover effect. This may delay, defer or prevent a tender offer or takeover attempt that a shareholder might consider in its best interests, including those attempts that might result in a premium over the market price for its shares.

Authorized Capital Stock

Our Certificate of Incorporation authorizes us to issue 450,400,000 shares of stock of all classes, of which 450,000,000 shares shall be common stock, par value $1.00 per share, and 400,000 shares shall be cumulative preferred stock, par value $100 per share. No shares of stock of any class have any preemptive or preferential right to purchase or subscribe to any shares of stock of any class or any notes, debentures, bonds, or other securities convertible into or carrying options or warrants to purchase shares of any class, other than such rights as the Board of Directors may grant and at such prices as the Board of Directors may fix. The Board of Directors may issues shares of stock of any class, or any notes, debentures, bonds or other securities convertible into or carrying options or warrants to purchase shares of stock of any class, without offering any such shares of stock of any class, either in whole or in part, to the existing stockholders of any class.

Common Stock

Except as provided by our Certificate of Incorporation or by law, each holder of common stock shall have the right, to the exclusion of all other classes of stock, to one vote for each share of stock standing in the name of such holder on the books of the Company. Subject to preferences that may be applicable to any outstanding preferred stock, the holders of common stock are entitled to receive ratably such dividends, if any, as may be declared from time to time by the Board of Directors out of funds legally available therefor. In the event of liquidation, dissolution or winding up of Murphy Oil, the holders of common stock are entitled to share ratably in all assets remaining after payment of liabilities, subject to prior distribution rights of preferred stock, if any, then outstanding. There are no redemption or sinking fund provisions applicable to the common stock. All outstanding shares of common stock are fully paid and non-assessable, and the shares of common stock to be issued upon completion of this offering will be fully paid and non-assessable. The common stock is listed on the New York Stock Exchange. The transfer agent and registrar for the common stock is Computershare Investor Services, LLC.

Preferred Stock

The Board of Directors has the authority to issue the preferred stock in one or more series and to fix the rights, preferences, privileges and restrictions thereof, including dividend rights, dividend rates, conversion or exchange rights, voting rights, terms of redemption, redemption prices, liquidation preferences, use of purchase, retirement or sinking funds and the number of shares constituting any series of the designation of such series, without further vote or action by the shareholders. The issuance of preferred stock may have the effect of delaying, deferring or preventing a change in control of Murphy Oil without further action by the shareholders and may adversely affect the voting and other rights of the holders of common stock. We may further amend from time to time our Certificate of Incorporation to increase the number of authorized shares of preferred stock.

An amendment would require the approval of the holders of a majority of the outstanding shares of our preferred stock. As of the date of this prospectus, we have not issued any preferred stock.

Certain Anti-Takeover Effects of Delaware Law

We are subject to Section 203 of the DGCL ("Section 203"). In general, Section 203 prohibits a publicly held Delaware corporation from engaging in various "business combination" transactions with any interested stockholder for a period of three years following the date of the transactions in which the person became an interested stockholder, unless:

- the transaction is approved by the board of directors prior to the date the interested stockholder obtained such status;
- upon consummation of the transaction which resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced; or
- on or subsequent to such date the business combination is approved by the board and authorized at an annual or special meeting of stockholders by the affirmative vote of at least 66⅔% of the outstanding voting stock which is not owned by the interested stockholder.

A "business combination" is defined to include mergers, asset sales, and other transactions resulting in financial benefit to a stockholder. In general, an "interested stockholder" is a person who, together with affiliates and associates, owns (or within three years, did own) 15% or more of a corporation's voting stock. The statute could prohibit or delay mergers or other takeover or change in control attempts with respect to Murphy Oil and, accordingly, may discourage attempts to acquire Murphy Oil even though such a transaction may offer Murphy Oil's stockholders the opportunity to sell their stock at a price above the prevailing market price.

FIRST AMENDMENT TO THE MURPHY OIL CORPORATION 2012 LONG-TERM INCENTIVE PLAN

THIS FIRST AMENDMENT, effective as of January 22, 2020 (the "**Effective Date**"), amends the Murphy Oil Corporation (the "**Company**") 2012 Long-Term Incentive Plan (the "**Plan**"). Capitalized terms used and not otherwise defined herein shall have the meanings assigned to them in the Plan.

RECITALS

WHEREAS, the Company has established and maintains the Plan;

WHEREAS, pursuant to Section 19 of the Plan, the Board may amend the Plan;

WHEREAS, effective upon the Effective Date, the Company desires to amend the Plan as set forth herein.

NOW, THEREFORE, as of the Effective Date:

1. The last sentence of Section 18 of the Plan is amended to read as follows:

"The Committee may provide for or permit (i) the minimum statutory tax withholding obligations, or (ii) for Awards (x) granted prior to January 31, 2020 that vest on or after January 31, 2020 and (y) new Awards granted on or after January 31, 2020, any applicable withholding obligations to the extent such withholding would not result in liability classification of such Award (or any portion thereof) pursuant to FASB ASC Subtopic 718-10, to be satisfied through the mandatory or elective sale of Shares and/or by having the Company withhold a portion of the Shares that otherwise would be issued to the Participant upon exercise of the Option or the vesting or settlement of an Award, or by tendering Shares previously acquired."

2. All other terms and provisions of the Plan shall remain unchanged and in full force and effect.

Exhibit 10.15

FIRST AMENDMENT TO THE MURPHY OIL CORPORATION 2018 LONG-TERM INCENTIVE PLAN

THIS FIRST AMENDMENT, effective as of January 22, 2020 (the "**Effective Date**"), amends the Murphy Oil Corporation (the "**Company**") 2018 Long-Term Incentive Plan (the "**Plan**"). Capitalized terms used and not otherwise defined herein shall have the meanings assigned to them in the Plan.

RECITALS

WHEREAS, the Company has established and maintains the Plan;

WHEREAS, pursuant to Section 19 of the Plan, the Board may amend the Plan;

WHEREAS, effective upon the Effective Date, the Company desires to amend the Plan as set forth herein.

NOW, THEREFORE, as of the Effective Date:

1. The last sentence of Section 18 of the Plan is amended to read as follows:

"The Committee may provide for or permit (i) the minimum statutory tax withholding obligations, or (ii) for Awards (x) granted prior to January 31, 2020 that vest on or after January 31, 2020 and (y) new Awards granted on or after January 31, 2020, any applicable withholding obligations to the extent such withholding would not result in liability classification of such Award (or any portion thereof) pursuant to FASB ASC Subtopic 718-10, to be satisfied through the mandatory or elective sale of Shares and/or by having the Company withhold a portion of the Shares that otherwise would be issued to the Participant upon exercise of the Option or the vesting or settlement of an Award, or by tendering Shares previously acquired."

2. All other terms and provisions of the Plan shall remain unchanged and in full force and effect.

Exhibit 10.17

MURPHY OIL CORPORATION

PERFORMANCE-BASED RESTRICTED STOCK UNIT GRANT AGREEMENT

Performance-Based Restricted Stock Unit Award Number [[GRANTNUMBER]]	Name of Grantee [[FIRSTNAME]] [[MIDDLENAME]] [[LASTNAME]]	Target Number of Performance-Based Restricted Stock Units Subject to this Grant [[SHARESGRANTED]]

This Performance-Based Restricted Stock Unit Award (this "Award") is granted on and dated [[GRANTDATE]] (the "Grant Date"), by Murphy Oil Corporation, a Delaware corporation (the "Company"), pursuant to and for the purposes of the 2018 Long-Term Incentive Plan (the "Plan"). Any terms used herein and not otherwise defined shall have the meanings set forth in the Plan.

This Agreement is subject to the following terms and provisions. In addition, certain terms and provisions applicable to this Award may be communicated to you in a separate brochure (the "Brochure"). By accepting this Agreement, you agree to the terms and provisions set forth below, in the Plan and in the Brochure.

1. The Company hereby grants to the employee named above (the "Grantee") the target number of Performance-Based Restricted Stock Units set forth above ("Target RSUs"), each equal in value to one share of Common Stock.

2. This Award is subject to the following vesting and time lapse restrictions:

(a) In the event that the Performance Measures as set forth in Section 3 below are satisfied in accordance with the Plan, the size of this Award will be determined by the Committee, and the Grantee will be paid the value of his or her earned Target RSUs in Shares during the first quarter of the fiscal year immediately following the completion of the Performance Measurement Period (as defined below); *provided* that, except as set forth in Sections 2(c), 2(d) and 2(e) below, the Grantee is employed by the Company on both the last day of the Performance Measurement Period and the date that the Committee determines the size of this Award.

(b) In the event that the Grantee's employment terminates any time prior to the date that the Committee determines the size of this Award, except as set forth in Sections 2(c), 2(d) and 2(e) below, he or she will forfeit all Target RSUs pursuant to this Award.

(c) In the event of the Grantee's death, disability, or retirement (as determined in accordance with the Plan), the Grantee will receive the pro-rata number of Target RSUs earned for performance completed based upon the number of months worked pursuant to this Award up to the time of the death, disability, or retirement event. In the event that the Performance Measures are satisfied in accordance with the Plan and, as set forth in Section 3 below, and the size of this Award is determined by the Committee, the Grantee will be paid his or her Shares during the first quarter of the fiscal year immediately following the completion of the Performance Measurement Period.

(d) If the Grantee is not an employee of the Company who is (i) the Chief Executive Officer of the Company ("CEO"), (ii) an employee who reports directly to the CEO, or (ii) a Named Executive Officer of the Company, in each case, at any time during the period beginning on the Grant Date and ending on the date on which a Change in Control occurs, this Award will fully vest and one hundred percent (100%) of the Target RSUs granted will be deemed to be earned at the target level of performance and will be paid in full, without restrictions, upon such Change in Control; *provided, however*, that no payment will be made until the first quarter of 2023 unless such Change in Control also qualifies as a "change in control event" as determined under Section 409A.

(e) If the Grantee is an employee of the Company who is (i) the CEO, (ii) an employee who reports directly to the CEO, or (iii) a Named Executive Officer, in each case, at any time during the period beginning on the Grant Date and ending on the date on which a Change in Control occurs, this Award will fully vest and one hundred percent (100%) of the Target RSUs granted will be deemed to be earned at the target level of performance and will be paid in full, without restrictions, upon the occurrence of the Grantee's Qualifying Termination of Employment. "Qualifying Termination of Employment" means the termination of the Grantee's employment within the two-year period immediately following a Change in Control (x) by the Company or any of its affiliates without Cause or (y) by the Grantee for Good Reason. Upon a Qualifying Termination of Employment, payment will be made as soon as reasonably practicable following the date of the Qualifying Termination of Employment, less any Shares or amounts deducted for applicable withholding taxes.

(f) For purposes of this Agreement, "Cause" means the occurrence of any of the following:

(i) Any act or omission by the Grantee which constitutes a material willful breach of the Grantee's obligations to the Company or any of its affiliates or the Grantee's continued and willful refusal to substantially perform satisfactorily any duties reasonably required of the Grantee, which results in material injury to the interest or business reputation of the Company or any of its affiliates and which breach, failure or refusal (if susceptible to cure) is not corrected (other than failure to correct by reason of the Grantee's incapacity due to physical or mental illness) within thirty (30) days after written notification thereof to the Grantee by the Company; *provided* that no act or failure to act on the Grantee's part shall be deemed willful unless done or omitted to be done by the Grantee not in good faith and without reasonable belief that the Grantee's action or omission was in the best interest of the Company or its affiliates;

(ii) The Grantee's commission of any dishonest or fraudulent act, which has caused or may reasonably be expected to cause a material injury to the interest or business reputation of the Company or any of its affiliates;

(iii) The Grantee's plea of guilty or *nolo contendere* to or conviction of a felony under the laws of the United States or any state thereof or any other plea or confession of a similar crime in a jurisdiction in which the Company or any of its affiliates conducts business; or

(iv) The Grantee's commission of a fraudulent act or participation in misconduct which leads to a material restatement of the Company's financial statements.

(g) For purposes of this Agreement, "Good Reason" means the occurrence of any of the following:

(i) Any material diminution in the Grantee's title, status, position, the scope of duties assigned, responsibilities or authority, including the assignment to the Grantee of any duties, responsibilities or authority in any manner adverse to the Grantee or inconsistent with the duties, responsibilities and authority assigned to the Grantee prior to a Change in Control;

(ii) Any reduction in the Grantee's base salary, annual target cash bonus opportunity or long-term incentive award opportunity immediately prior to a Change in Control;

(iii) A relocation of more than fifty (50) miles from the location of the Grantee's principal job location or office prior to a Change in Control; or

(iv) Any other action or inaction that constitutes a material breach by the Company or any of its affiliates of any employment or similar agreement pursuant to which the Grantee provides services to the Company or any of its affiliates;

provided, that the Grantee provides the Company with a written notice of termination indicating the Grantee's intent to terminate his or her employment for Good Reason within ninety (90) days after the Grantee becoming aware of any circumstances set forth above, that the Grantee provides the Company with at least thirty (30) days following receipt of such notice to remedy such circumstances, and, if the Company fails to remedy such circumstances during such thirty (30) day period, that the Grantee terminates his or her employment no later than sixty (60) days after the end of such thirty (30) day period.

3. The "Performance Measures" for this Award are: (i) 80% of the Target RSUs (the "TSR Units") shall be based on and subject to the achievement of the Company's total shareholder return ("TSR") over the Performance Measurement Period compared to the TSR of the Company's peer group, and (ii) 20% of the Target RSUs (the "EBITDA/ACE Units") shall be based on and subject to the achievement of the amount determined by dividing (a) the sum of the Company's cumulative earnings before interest, tax, depreciation and amortization for each of the three years in the Performance Measurement Period (Cumulative EBITDA), by (b) the sum of the Company's average capital employed for each of the three years in the Performance Measurement Period (ACE). The number of Target RSUs earned (the "Payout Percentage") is detailed in the tables below.

   a. TSR Performance Measure. The number of TSR Units earned will be based on the Company's percentile ranking in TSR over the Performance Measurement Period compared to that of the Company's peer group, as set forth in the table below:

TSR Percentile Rank	**Payout Percentage**
Below 25th Percentile	0%
25th Percentile (Threshold)	50%
50th Percentile (Target)	100%
75th Percentile	125%
At or Above 90th Percentile (Maximum)	150%

   The Payout Percentage in respect of the TSR Units will be interpolated for points between the Threshold and Maximum performance levels. Notwithstanding the foregoing, if the Company's TSR over the Performance Measurement Period is less than 0%, the Payout Percentage shall not exceed 100%.

   b. EBITDA/ACE Performance Measure. The number of EBITDA/ACE Units earned will be based on the Company's achievement of the amount determined by dividing the Cumulative EBITDA by the ACE, as defined above, for the Performance Measurement Period, as set forth in the table below:

EBITDA/ACE Performance Level	**Payout Percentage**
Below 16.16%	0%
16.16% (Threshold)	50%
20.20% (Target)	100%
24.24% or Above (Maximum)	200%

   The Payout Percentage in respect of the EBITDA/ACE Units will be interpolated for points between the Threshold and Maximum performance levels.

   c. Performance Measurement Period. The "Performance Measurement Period" under this Award is January 1, 2020 through December 31, 2022.

4. Provided that the Performance Measures as set forth in Section 3 above are satisfied and Shares are to be paid to the Grantee without restriction, such Shares paid will be the net Shares earned pursuant to Section 3 above less the number of Shares which must be withheld to satisfy the tax withholding requirements applicable to such payment of Shares.

5. In the event of any relevant change in the capitalization of the Company prior to the issuance of Shares underlying the Target RSUs, the number of Target RSUs may be equitably adjusted pursuant to the Plan to reflect that change.

6. This Award is not assignable except as provided under the Plan in the case of death and is not subject in whole or in part to attachment, execution, or levy of any kind.

7. The Grantee shall have no voting rights with respect to Shares underlying the Target RSUs unless and until such Shares are reflected as issued and outstanding shares on the Company's stock ledger.

8. The Grantee is eligible to receive a payment equivalent to the dividends paid on shares of Common Stock equal in number to the Target RSUs granted hereunder. These dividend equivalents will be accrued over the performance period and included in any Shares issued at the end of the period. In the event that Shares are not earned, the accompanying accrued dividend equivalents will be forfeited.

9. The Plan, this Agreement and the Brochure are administered by the Committee. The Committee has the full authority and discretion to interpret and administer the Plan consistent with the terms and provisions of the Plan.

Attest: Murphy Oil Corporation

___________________________________ By___________________________________

Exhibit 10.24

SECOND AMENDMENT TO THE
MURPHY OIL CORPORATION
2018 STOCK PLAN FOR NON-EMPLOYEE DIRECTORS

WHEREAS, the Murphy Oil Corporation 2018 Stock Plan for Non-Employee Directors, effective as of May 9, 2018 (the "Plan"), was adopted by the Board of Directors (the "Board") of Murphy Oil Corporation (the "Company") to enhance the ability of the Company to attract and retain directors who are in a position to make significant contributions to the success of the Company and to reward directors for such contributions; and

WHEREAS, pursuant to Section XII of the Plan, the Board has the authority to amend the Plan at any time.

NOW THEREFORE, effective February 5, 2020, the Plan is amended in the manner as set forth below:

1. Section IV is amended to replace paragraphs (1) with the following:

   Subject to any adjustment as provided in Section XI, an aggregate of 500,000 shares of Common Stock shall be available for issuance of grants under the Plan. In no event shall any individual Participant receive compensation with respect to any calendar year, including grants of awards under the Plan and any cash fees paid to such Participant for services rendered for such calendar year, in excess of $750,000, with the value of any shares of Common Stock subject to awards granted under the Plan calculated based on the aggregate Fair Market Value (or in the case of Stock Options, the grant date value of such Stock Options as determined by the Committee) of such shares of Common Stock at the time of grant. The shares of Common Stock deliverable upon the exercise of Stock Options or the award or settlement of Restricted Stock or Restricted Stock Units may be made available from authorized but unissued Common Shares or Common Shares reacquired by the Company, including Common Shares purchased in the open market. If any grants under the Plan shall be cancelled, forfeited, expire or terminate for any reason without Common Shares having been delivered, the Common Shares subject to, but not delivered under, such grants may again become available for the grant of other Stock Options, Restricted Stock, or Restricted Stock Units under the Plan. No Common Shares deliverable to the Company in full or partial payment of the purchase price payable pursuant to Section VI of the Plan shall become available for the grant of other Stock Options, Restricted Stock, or Restricted Stock Units under the Plan.

This second amendment to the Plan has been approved by the Board as of this 5th day of February, 2020.

MURPHY OIL CORPORATION

RESTRICTED STOCK UNIT GRANT AGREEMENT

Restricted Stock Unit Award Number:	Name of Grantee:	Number of Restricted Stock Units Subject to this Grant:

This Restricted Stock Unit Award is granted on and dated **[•]**, by Murphy Oil Corporation, a Delaware corporation (the Company), pursuant to and for the purposes of the 2018 Stock Plan for Non-Employee Directors (the “Plan”) adopted by the stockholders of the Company on May 9, 2018, subject to the provisions set forth herein and in the Plan. Any terms used herein and not otherwise defined shall have the meaning set forth in the Plan.

1. The Company hereby grants to the individual named above (the Awardee) an award of Restricted Stock Units each equal in value to one share of Common Stock. This award constitutes a right to receive shares in the future and does not represent any current interest in the shares subject to the award.

2. Subject to paragraph 3 below and in accordance with the Plan, this award will fully vest on the earlier of (a) the first anniversary of the date of grant, **[•]**, or (b) such earlier termination of service as a member of the Board (the “Vesting Date”) provided for in the Plan, and Common Shares and any accrued dividend equivalents will be issued, without restrictions, within thirty days following the Vesting Date or, in the case of Deferred Units, the settlement date selected at the time a valid deferral election was made in accordance with the Plan (the “Settlement Date”). This award shall not be settled whenever the delivery of shares of Common Stock under it would be a violation of any applicable law, rule or regulation.

3. The Restricted Stock Unit Award will fully vest and 100 percent of the Restricted Stock Units will be deemed to be earned and Common Shares will be issued, without restrictions, upon the occurrence of a Change in Control (as such term is defined in the Plan) provided, however, that no issuance of shares will be made until **[•]** unless the Change in Control also qualifies as a change in the ownership or effective control of Murphy Oil Corporation, or in the ownership of a substantial portion of its assets, as determined under Section 409A of the Internal Revenue Code.

4. In the event of any relevant change in the capitalization of the Company subsequent to the date of this grant and prior to its vesting, the number of Restricted Stock Units will be adjusted to reflect that change.

5. In accordance with the Plan, settlement of the Restricted Stock Unit Award may be deferred to the extent the Company received from the holder of the Restricted Stock Units an executed valid deferral election form, in compliance with such rules and procedures as the Committee deems advisable, no later than December 31 of the calendar year prior to the year in which the Restricted Stock Unit Award was granted.

6. This Restricted Stock Unit Award is not assignable except as provided in the case of death and is not subject in whole or in part to attachment, execution or levy of any kind.

7. The holder of the Restricted Stock Units shall not be eligible to receive any dividends or other distributions paid with respect to the underlying Common Shares prior to the Settlement Date. An amount equivalent to these dividends and/or other distributions shall be paid to the holder on the Settlement Date. Any such payment (unadjusted for interest) shall be made in whole shares of the $1.00 par value Common Stock of the Company and in cash equal to the value of any fractional shares.

Attest: **MURPHY OIL CORPORATION**

________________________________ By ________________________________

EXHIBIT 21.1

MURPHY OIL CORPORATION
SUBSIDIARIES OF THE REGISTRANT AS OF DECEMBER 31, 2019

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
Murphy Oil Corporation (REGISTRANT)		
A. Arkansas Oil Company	Delaware	100.00
B. Caledonia Land Company	Delaware	100.00
C. El Dorado Engineering Inc.	Delaware	100.00
1. El Dorado Contractors	Delaware	100.00
2. El Dorado Exploracion y Produccion, S. de. R.L. de C.V. (see company F.3.b(1) below)	Mexico	10.00
D. Marine Land Company	Delaware	100.00
E. Murphy Eastern Oil Company	Delaware	100.00
F. Murphy Exploration & Production Company	Delaware	100.00
1. Mentor Holding Corporation	Delaware	100.00
a. Mentor Excess and Surplus Lines Insurance Company	Delaware	100.00
b. MIRC Corporation	Louisiana	100.00
2. Murphy Building Corporation	Delaware	100.00
3. Murphy Exploration & Production Company - International	Delaware	100.00
a. Canam Offshore Limited	Bahamas	100.00
(1) Canam Brunei Oil Ltd.	Bahamas	100.00
(2) Murphy Peninsular Malaysia Oil Co., Ltd.	Bahamas	100.00
(3) Murphy Cuu Long Tay Oil Co., Ltd.	Bahamas	100.00
b. El Dorado Exploration, S.A.	Delaware	100.00
(1) El Dorado Exploracion y Produccion, S. de. R.L. de C.V.	Mexico	90.00
c. Murphy Asia Oil Co., Ltd.	Bahamas	100.00
e. Murphy Brasil Exploracao e Producao de Petroleo e Gas Ltda. (see company l.(1) below)	Brazil	90.00
f. Murphy Cuu Long Bac Oil Co., Ltd.	Bahamas	100.00
g. Murphy Dai Nam Oil Co., Ltd.	Bahamas	100.00
h. Murphy Equatorial Guinea Oil Co., Ltd.	Bahamas	100.00
i. Murphy Exploration (Alaska), Inc.	Delaware	100.00
j. Murphy Luderitz Oil Co., Ltd.	Bahamas	100.00
k. Murphy Nha Trang Oil Co., Ltd.	Bahamas	100.00
l. Murphy Overseas Ventures Inc.	Delaware	100.00
(1) Murphy Brasil Exploracao e Producao de Petroleo e Gas Ltda.	Brazil	10.00
m. Murphy Phuong Nam Oil Co., Ltd.	Bahamas	100.00
n. Murphy Semai IV Ltd.	Bahamas	100.00
o. Murphy South Barito, Ltd.	Bahamas	100.00
p. Murphy-Spain Oil Company	Delaware	100.00
q. Murphy West Africa, Ltd.	Bahamas	100.00
r. Murphy Worldwide, Inc.	Delaware	100.00
s. Murphy Offshore Oil Co. Ltd.	Bahamas	100.00
t. Murphy Netherlands Holdings B.V.	Netherlands	100.00

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
(1) Murphy Sur, S. de R. L. de C.V. (see company t(2)a. below)	Mexico	0.01
(2) Murphy Netherlands Holdings II B.V.	Netherlands	100.00
a. Murphy Sur, S. de R. L. de C.V.	Mexico	99.99
u. Murphy Australia Holdings Pty. Ltd	Western Australia	100.00
v. Murphy Exploration Holdings, LLC	Delaware	100.00
(1) Murphy Australia Oil Pty. Ltd.	Western Australia	100.00
a. Murphy Australia AC/P 36 Oil Pty. Limited	Western Australia	100.00
(2) Murphy Australia AC/P 57 Oil Pty. Ltd.	Western Australia	100.00
(3) Murphy Australia AC/P 58 Oil Pty. Ltd.	Western Australia	100.00
(4) Murphy Australia EPP43 Oil Pty. Ltd.	Western Australia	100.00
(5) Murphy Australia NT/P80 Oil Pty. Ltd	Western Australia	100.00
(6) Murphy Australia WA-408-P Oil Pty. Ltd.	Western Australia	100.00
(7) Murphy Australia WA-476-P Oil Pty. Ltd.	Western Australia	100.00
(8) Murphy Australia WA-481-P Oil Pty. Ltd.	Western Australia	100.00
(9) Murphy Australia AC/P 59 Oil Pty. Ltd.	Western Australia	100.00
4. Murphy Exploration & Production Company - USA	Delaware	100.00
a. MP Gulf of Mexico, LLC	Delaware	80.00
G. Murphy Oil Company Ltd.	Canada	100.00
1. Murphy Canada Holding ULC	AULC	100.00
2. Murphy Canada, Ltd.	Canada	100.00
H. New Murphy Oil (UK) Corporation	Delaware	100.00
1. Murphy Petroleum Limited	England	100.00
a. Murco Petroleum Limited	England	100.00

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Murphy Oil Corporation:

We consent to the incorporation by reference in the registration statement (No. 333-226494) on Form S-8 and in the registration statement (No. 333-227875) on Form S-3 of Murphy Oil Corporation of our reports dated February 26, 2020, with respect to the consolidated balance sheets of Murphy Oil Corporation and subsidiaries as of December 31, 2019 and 2018, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2019, and the related notes and financial statement Schedule II (collectively, the consolidated financial statements), and the effectiveness of internal control over financial reporting as of December 31, 2019, which reports appear in the December 31, 2019 annual report on Form 10-K of Murphy Oil Corporation.

Our report refers to a change in the method of accounting for leases as of January 1, 2019 due to the adoption of Accounting Standards Update No. 2016-02, *Leases*.

/s/ KPMG LLP

Houston, Texas
February 26, 2020

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

CONSENT OF RYDER SCOTT COMPANY, L.P.

We hereby consent to the incorporation by reference in the Registration Statement (File No. 333-226494) on Form S-8, the Registration Statement (File No. 333-227875) on Form S-3 of Murphy Oil Corporation, and of the reference to our reports regarding certain assets in the United States effective December 31, 2019 and dated January 29, 2020 for Murphy Oil Corporation, which appears in the December 31, 2019 annual report on Form 10-K of Murphy Oil Corporation, including any reference to our firm under the heading “Experts”.

/s/ RYDER SCOTT COMPANY, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
February 20, 2020

MCDANIEL

Trond Mathisen
General Manager - Corporate Reserves Group
Murphy Oil Corporation
9805 Katy Freeway, Suite G-200
Houston, TX 77024

We hereby consent to the reference of our firm and to the use of our reports conducting an audit of the Canadian Oil and Gas Properties for the Greater Kaybob Duvernay, Tupper and Tupper West Montney, as well as Hibernia Main, Hibernia Southern Extension and the Terra Nova projects effective December 31, 2019 and dated January 23, 2020 in the Murphy Oil Corporation Registration Statement Form S-8, No. 333-226494 and Registration Statement Form S-3, No. 333-227875 and in any related prospectus, including any reference to our firm under the heading “Experts” in such prospectus.

McDaniel & Associates Consultants Ltd.

/s/ Jared W. B. Wynveen

Jared W. B. Wynveen, P. Eng.
Executive Vice President

January 23, 2020
APEGA PERMIT NUMBER: P3145

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Roger W. Jenkins, certify that:

1. I have reviewed this annual report on Form 10-K of Murphy Oil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal controls over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions)

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: February 26, 2020

/s/ Roger W. Jenkins

Roger W. Jenkins
Principal Executive Officer

EXHIBIT 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David R. Looney, certify that:

1. I have reviewed this annual report on Form 10-K of Murphy Oil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal controls over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal controls over financial reporting.

Date: February 26, 2020

/s/ David R. Looney

David R. Looney
Principal Financial Officer

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Murphy Oil Corporation (the "Company") on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), we, Roger W. Jenkins and David R. Looney, Principal Executive Officer and Principal Financial Officer, respectively, of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to our knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 26, 2020

/s/ Roger W. Jenkins

Roger W. Jenkins
Principal Executive Officer

/s/ David R. Looney

David R. Looney
Principal Financial Officer

Exhibit 99.1

MURPHY OIL CORPORATION

Estimated

Future Reserves

Attributable to Certain

Leasehold Interests

U.S. Onshore

Gulf of Mexico

SEC Parameters

As of

December 31, 2019

/s/ Eric T. Nelson	/s/ Val Rick Robinson
Eric T. Nelson, P.E.	Val Rick Robinson, P.E.
TBPE License No. 102286	TBPE License No. 105137
Managing Senior Vice President	Managing Senior Vice President

[SEAL] **[SEAL]**

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA STREET SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 30, 2020

Trond Mathisen
General Manager - Corporate Reserves Group
Murphy Oil Corporation
9805 Katy Freeway, Suite G-200
Houston, TX 77024

Gentlemen:

At the request of Murphy Oil Corporation (Murphy), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2019 prepared by Murphy's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on January 10, 2020 and presented herein, was prepared for public disclosure by Murphy in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. For the U.S. Onshore properties, the estimated reserves shown herein represent Murphy's estimated net reserves attributable to the leasehold interests in certain properties owned by Murphy and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2019. For the Gulf of Mexico (GOM) properties, the estimated reserves shown herein exclude the net reserves attributable to Murphy's leasehold interests in the Murphy and Petrobras GOM JV (MPGOM). The net reserves attributable to the MPGOM assets are included in a separate Ryder Scott report dated January 29, 2020. The properties reviewed and included herein by Ryder Scott incorporate Murphy reserves determinations and are located onshore in the state of Texas and Louisiana and in the federal waters offshore Louisiana.

The combined U.S. Onshore and GOM properties reviewed by Ryder Scott account for a portion of Murphy's total net proved reserves as of December 31, 2019. Based on the estimates of total net proved reserves prepared by Murphy, the reserves audit conducted by Ryder Scott addresses 39 percent of the total proved developed net reserves on a barrel of oil equivalent, BOE basis and 58 percent of the total proved undeveloped net reserves on a barrel of oil equivalent, BOE basis of Murphy.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

SUITE 800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799 FAX (403) 262-2790
633 17TH STREET, SUITE 1700 DENVER, COLORADO 80202 TEL (303) 339-8110

Based on our review, including the data, technical processes and interpretations presented by Murphy, it is our opinion that the overall procedures and methodologies utilized by Murphy in preparing their estimates of the proved reserves as of December 31, 2019 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Murphy are, in the aggregate and within each geographic area, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. Murphy has informed us that in the preparation of their reserves and income projections, as of December 31, 2019, they used average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and amounts of income actually received may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Murphy attributable to Murphy's interest and entitlement in properties that we reviewed are summarized by geographic area as follows.

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold Interests
Murphy Oil Corporation

As of December 31, 2019

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Audited by Ryder Scott				
U.S. Onshore				
Net Reserves				
Oil/Condensate – MBBL	89,067	1,183	111,325	201,575
Plant Products – MBBL	18,783	203	22,583	41,569
Gas – MMCF	170,070	1,076	112,772	283,918
MBOE	136,195	1,565	152,703	290,463

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Gulf of Mexico (GOM)				
Net Reserves				
Oil/Condensate – MBBL	21,008	5,596	39,292	65,896
Plant Products – MBBL	2,429	1,373	2,831	6,633
Gas – MMCF	33,470	13,119	38,870	85,459
MBOE	29,015	9,156	48,601	86,772

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (MBBL). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. Certain gas volumes that are consumed as fuel in operations are also included as net gas reserves; these volumes represent 72,480 MMcf, or 4.2 percent of the total U.S. Onshore net MBOE and 3,892 MMcf, or 0.7 percent of the total GOM net MBOE. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent.

Murphy's estimates of the reserves attributable to properties in this report were prepared using the economic software package Val Nav™, a copyrighted program of Aucerna. Ryder Scott notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. The rounding differences are not material.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various proved reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the shut-in and behind pipe status categories.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Murphy's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves, prepared by Murphy, for the properties that we reviewed were estimated by performance methods, the volumetric method, analogy, or a combination of methods. The proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were primarily estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through September, 2019, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Murphy or obtained from public data sources and were considered sufficient for the purpose thereof. Certain proved producing reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate.

Most of the proved developed non-producing and undeveloped reserves that we reviewed were estimated by performance methods, analogy, or a combination of methods. Certain proved non- developed and undeveloped reserves that we reviewed were estimated by the volumetric method or a combination of methods. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Murphy for our review or which we have obtained from public data sources that were available through December, 2019. The data utilized from the analogues in conjunction with well and seismic data incorporated into the volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Murphy relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by Murphy for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices in effect on December 31, 2019 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used by Murphy for the geographic areas reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used by Murphy to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used by Murphy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Murphy.

The table below summarizes Murphy's net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as Murphy's "average realized prices." The average realized prices shown in the table below were determined from Murphy's estimate of the total future gross revenue before production taxes for the properties reviewed by us and Murphy's estimate of the total net reserves for the properties reviewed by us for the geographic areas. At Murphy's request, also provided is the average realized gas price excluding fuel gas. The data shown in the table below is presented in accordance with SEC disclosure requirements for each of the geographic areas reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices	Average Realized Prices *
North America					
United States	Oil/Condensate	WTI Cushing	$55.69/BBL	$59.60/BBL	$59.60/BBL
- Offshore	NGLs	WTI Cushing	$55.69/BBL	$12.77/BBL	$12.77/BBL
	Gas	Henry Hub	$2.577/MMBTU	$2.49/MCF	$2.61/MCF
United States	Oil/Condensate	WTI Cushing	$55.69/BBL	$58.42/BBL	$58.42/BBL
- Onshore	NGLs	WTI Cushing	$55.69/BBL	$11.48/BBL	$11.48/BBL
	Gas	Henry Hub	$2.577/MMBTU	$1.43/MCF	$1.93/MCF

* Realized prices excluding fuel gas volumes, as previously noted.

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Murphy's individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed.

Operating costs furnished by Murphy are based on the operating expense reports of Murphy and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished by Murphy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Murphy. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Murphy are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Murphy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Murphy. The estimated net cost of abandonment after salvage was included by Murphy for properties where abandonment costs net of salvage were material. Murphy's estimates of the net abandonment costs were accepted without independent verification.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Murphy's plans to develop these reserves as of December 31, 2019. The implementation of Murphy's development plans as presented to us is subject to the approval process adopted by Murphy's management. As the result of our inquiries during the course of our review, Murphy has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Murphy's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Murphy. Murphy has provided written documentation supporting their commitment to proceed with the development activities as presented to us**.** Additionally, Murphy has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2019, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Murphy were held constant throughout the life of the properties.

Murphy's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by Murphy to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Murphy. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Murphy's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Murphy's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons including the granting, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a review of the properties in which Murphy owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by Murphy for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of Murphy are responsible for the preparation of reserves estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Murphy has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Murphy's forecast of future proved production, we have relied upon data furnished by Murphy with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, excess profits taxes, export taxes, unrecovered cost balances, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Murphy. We consider the factual data furnished to us by Murphy to be appropriate and sufficient for the purpose of our review of Murphy's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by Murphy and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Murphy, it is our opinion that the overall procedures and methodologies utilized by Murphy in preparing their estimates of the proved reserves as of December 31, 2019 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Murphy are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by Murphy in their estimation of proved reserves to be effective and, in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with Murphy's estimates of proved reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between Murphy's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to Murphy when its reserves estimates were prepared. In these cases, Murphy revised its estimates to better conform to our estimates. As a consequence, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by Murphy.

Other Properties

Other properties, as used herein, are those properties of Murphy which we did not review. The proved net reserves attributable to the other properties account for 41 percent of the total proved net reserves on an equivalent barrel, BOE, basis based on estimates prepared by Murphy as of December 31, 2019.

The same technical personnel of Murphy were responsible for the preparation of the reserves estimates for the properties that we reviewed as well as for the properties not reviewed by Ryder Scott.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Murphy. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Murphy.

We have provided Murphy with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Murphy and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Eric T. Nelson

Eric T. Nelson, P.E.
TBPE License No. 102286
Managing Senior Vice President **[SEAL]**

/s/ Val Rick Robinson

Val Rick Robisnon, P.E.
TBPE License No. 105137
Managing Senior Vice President **[SEAL]**

ETN-VRR (GR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Eric T. Nelson is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Nelson, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2005, is a Managing Senior Vice President and a member of the Board of Directors. He is responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Nelson served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Nelson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Nelson earned a Bachelor of Science degree in Chemical Engineering from the University of Tulsa in 2002 (summa cum laude) and a Master of Business Administration from the University of Texas in 2007 (Dean's Award). He is a licensed Professional Engineer in the State of Texas. Mr. Nelson is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Nelson fulfills. As part of his 2019 continuing education hours, Mr. Nelson attended over 17 hours of training during 2019 covering such topics as updates concerning the implementation of the latest SEC oil and gas reporting requirements, evaluations of resource play reserves, evaluation of simulation models, procedures and software, and ethics training.

Based on his educational background, professional training and more than 14 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Nelson has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

MURPHY OIL CORPORATION

Estimated

Future Reserves

Attributable to the 100%

Leasehold Interests of the

Murphy Petrobras GOM JV

SEC Parameters

As of

December 31, 2019

/s/ Eric T. Nelson

Eric T. Nelson, P.E.
TBPE License No. 102286
Managing Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA STREET SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 29, 2020

Trond Mathisen
General Manager - Corporate Reserves Group
Murphy Oil Corporation
9805 Katy Freeway, Suite G-200
Houston, TX 77024

Gentlemen:

At the request of Murphy Oil Corporation (Murphy), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2019 prepared by Murphy's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on January 10, 2020 and presented herein, was prepared for public disclosure by Murphy in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. For the Gulf of Mexico properties, the estimated reserves shown herein represent the Murphy and Petrobras GOM JV (MPGOM) estimated net reserves attributable to Murphy's leasehold interests in certain properties owned by MPGOM. The properties reviewed by Ryder Scott incorporate Murphy reserves determinations and are located in federal waters offshore Louisiana and Alabama**.** Murphy's ownership interest in the MPGOM is 80 percent. The remaining 20 percent is owned by Petrobras.

The properties reviewed by Ryder Scott account for a portion of Murphy's total net proved reserves as of December 31, 2019. Based on the estimates of total net proved reserves prepared by Murphy, the reserves audit conducted by Ryder Scott addresses 17 percent of the total proved developed net reserves on a barrel of oil equivalent, BOE basis and 6 percent of the total proved undeveloped net reserves on a barrel of oil equivalent, BOE basis of Murphy. At your request, this report also presents the net reserves attributable to the 100% interests of the MPGOM, which includes the 20 percent non-controlling interest of Petrobras in MPGOM.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by Murphy, it is our opinion that the overall procedures and methodologies utilized by Murphy in preparing their estimates of the proved reserves as of December 31, 2019 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Murphy are reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. Murphy has informed us that in the preparation of their reserves and income projections, as of December 31, 2019, they used average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and amounts of income actually received may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Murphy attributable to Murphy's interest and entitlement in properties that we reviewed are summarized as follows. The net reserves below represent 100 percent of the Murphy and Petrobras GOM JV (MPGOM) and include the 20 percent non-controlling interest (NCI) of Petrobras:

SEC PARAMETERS
Estimated Net Reserves
Attributable to the 100 Percent Leasehold Interests of the
Murphy Petrobras GOM JV (MPGOM)

As of December 31, 2019

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves to MPGOM				
Oil/Condensate – MBarrels	81,345	7,904	21,040	110,289
Plant Products – MBarrels	3,185	297	1,163	4,645
Gas – MMcf	31,932	3,933	11,595	47,460
MBOE	89,852	8,857	24,136	122,845

Estimated Net Reserves
Attributable to Murphy's 80 Percent Leasehold Interests in the
Murphy Petrobras GOM JV (MPGOM)

As of December 31, 2019

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves to MPGOM				
Oil/Condensate – MBarrels	65,076	6,323	16,832	88,231
Plant Products – MBarrels	2,548	238	930	3,716
Gas – MMcf	25,546	3,146	9,276	37,968
MBOE	71,882	7,085	19,308	98,275

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (MBarrels). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the area in which the gas reserves are located. Certain gas volumes that are consumed as fuel in operations are also included as net gas reserves; these volumes represent 10,126 MMcf at Murphy's 80% interest of MPGOM, or 1.7 percent of the total GOM net MBOE. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent.

Murphy's estimates of the reserves attributable to properties in this report were prepared using the economic software package Val Nav™, a copyrighted program of Aucerna. Ryder Scott notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. The rounding differences are not material.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various proved reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the behind pipe status category.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Murphy's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves, prepared by Murphy, for the properties that we reviewed were estimated by performance methods or the volumetric method. The proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were primarily estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through September, 2019, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Murphy or obtained from public data sources and were considered sufficient for the purpose thereof. Certain proved producing reserves that we reviewed were estimated by the volumetric method. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate.

Most of the proved developed non-producing and undeveloped reserves that we reviewed were estimated by the volumetric method. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Murphy for our review or which we have obtained from public data sources that were available through December, 2019. Certain proved non-developed and undeveloped reserves that we reviewed were estimated by performance methods.

To estimate economically recoverable proved oil and gas reserves, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Murphy relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by Murphy for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices in effect on December 31, 2019 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used by Murphy for the geographic area reviewed by us. For certain properties, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used by Murphy to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used by Murphy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Murphy.

The table below summarizes Murphy’s net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as Murphy’s “average realized prices.” The average realized prices shown in the table below were determined from Murphy’s estimate of the total future gross revenue before production taxes for the properties reviewed by us and Murphy’s estimate of the total net reserves for the properties reviewed by us for the geographic area. At Murphy's request, also provided is the average realized gas price excluding fuel gas. The data shown in the table below is presented in accordance with SEC disclosure requirements for the geographic area reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices	Average Realized Prices *
North America					
United States - Offshore	Oil/Condensate	WTI Cushing	$55.69/Bbl	$59.34/Bbl	$59.34/Bbl
	NGLs	WTI Cushing	$55.69/Bbl	$9.30/Bbl	$9.30/Bbl
	Gas	Henry Hub	$2.577/MMBTU	$1.95 /Mcf	$2.65 /Mcf

* Realized prices excluding fuel gas volumes, as previously noted.

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Murphy's individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed.

Operating costs furnished by Murphy are based on the operating expense reports of Murphy and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements**.** The operating costs furnished by Murphy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Murphy. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Murphy are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Murphy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Murphy. The estimated net cost of abandonment after salvage was included by Murphy for properties where abandonment costs net of salvage were material. Murphy's estimates of the net abandonment costs were accepted without independent verification.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Murphy's plans to develop these reserves as of December 31, 2019. The implementation of Murphy's development plans as presented to us is subject to the approval process adopted by Murphy's management. As the result of our inquiries during the course of our review, Murphy has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Murphy's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Murphy. Murphy has provided written documentation supporting their commitment to proceed with the development activities as presented to us**.** Additionally, Murphy has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2019, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Murphy were held constant throughout the life of the properties.

Murphy's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by Murphy to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Murphy. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Murphy's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Murphy's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a review of the properties in which Murphy owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by Murphy for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of Murphy are responsible for the preparation of reserves estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Murphy has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Murphy's forecast of future proved production, we have relied upon data furnished by Murphy with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, excess profits taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Murphy. We consider the factual data furnished to us by Murphy to be appropriate and sufficient for the purpose of our review of Murphy's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by Murphy and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Murphy, it is our opinion that the overall procedures and methodologies utilized by Murphy in preparing their estimates of the proved reserves as of December 31, 2019 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Murphy are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by Murphy in their estimation of proved reserves to be effective and, in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with Murphy's estimates of proved reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between Murphy's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to Murphy when its reserves estimates were prepared. In these cases, Murphy revised its estimates to better conform to our estimates. As a consequence, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by Murphy in the the Murphy and Petrobras GOM JV (MPGOM).

Other Properties

Other properties, as used herein, are those properties of Murphy which we did not review. The proved net reserves attributable to the other properties account for 41 percent of the total proved net reserves on an equivalent barrel, BOE, basis based on estimates prepared by Murphy as of December 31, 2019.

The same technical personnel of Murphy were responsible for the preparation of the reserves estimates for the properties that we reviewed as well as for the properties not reviewed by Ryder Scott.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer’s license or a registered or certified professional geoscientist’s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Murphy. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Murphy.

We have provided Murphy with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Murphy and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Eric T. Nelson

Eric T. Nelson, P.E.
TBPE License No. 102286
Managing Senior Vice President **[SEAL]**

ETN (GR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Eric T. Nelson is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Nelson, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2005, is a Managing Senior Vice President and a member of the Board of Directors. He is responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Nelson served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Nelson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Nelson earned a Bachelor of Science degree in Chemical Engineering from the University of Tulsa in 2002 (summa cum laude) and a Master of Business Administration from the University of Texas in 2007 (Dean's Award). He is a licensed Professional Engineer in the State of Texas. Mr. Nelson is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Nelson fulfills. As part of his 2019 continuing education hours, Mr. Nelson attended over 17 hours of training during 2019 covering such topics as updates concerning the implementation of the latest SEC oil and gas reporting requirements, evaluations of resource play reserves, evaluation of simulation models, procedures and software, and ethics training.

Based on his educational background, professional training and more than 14 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Nelson has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

> *(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and*
>
> *(B) The project has been approved for development by all necessary parties and entities, including governmental entities.*

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

> *(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and*
>
> *(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.*

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

January 23, 2020

Murphy Oil Corporation
9805 Katy Freeway
Suite G-200
Houston, Texas
USA 77024

Attention: Mr. Trond Mathisen, General Manager, Corporate Reserves

Reference: Murphy Oil Corporation
Evaluation of the Canadian Oil and Gas Properties as of December 31, 2019

Dear Sir:

Pursuant to your request, McDaniel & Associates Consultants Ltd. ("McDaniel") has conducted an independent audit of Murphy Oil Corporation's ("Murphy") proved crude oil, natural gas and natural gas liquids reserves for Murphy's interests in the Greater Kaybob Project and the Tupper Montney Project located within the Provinces of Alberta and British Columbia, Canada; and the Hibernia Main, Hibernia Southern Extension, and Terra Nova projects (the "East Coast Canada properties") located within the Province of Newfoundland and Labrador, Canada. Murphy holds a 70 percent working interest in the Greater Kaybob Project, 99.88 percent working interest in the Tupper Montney Project, and a 6.5 percent working interest in the Hibernia Main Project, 4.3791 percent working interest in the Hibernia Southern Extension Project and 10.475 percent working interest in the Terra Nova Project. Murphy has represented that these properties account for approximately 40 percent of its total company proved reserves on an equivalent barrel basis as of December 31, 2019, and that its reserves estimates have been prepared in accordance with the United States Securities and Exchange Commission (SEC) definitions. We have reviewed information provided to us by Murphy that it represents to be its estimates of the reserves, as of December 31, 2019, for the same properties as those which we audited. The completion date of our report is January 23, 2020. This report was prepared in accordance with guidelines specified in Item 1202(a)(8) of Regulation S-K and is to be used for inclusion in certain filings of the SEC.

Reserves included herein are expressed as reserves as represented by Murphy. Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2019. Working interest reserves are defined as that portion of the gross reserves attributable to the interests owned by Murphy after deducting all working interests owned by others. Net reserves are defined as working interest reserves after the deduction of royalties.

Estimates of crude oil, natural gas and natural gas liquids reserves should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves estimates based on that information, which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this audit were obtained from reviews with Murphy personnel, Murphy files, from records on file with the appropriate regulatory agencies, and from public sources. In the preparation of this report we have relied, without independent verification, upon such information furnished by Murphy with respect to property interests, production from such properties, current costs of operation and development, prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. Furthermore, if in the course of our examination something came to our attention, which brought into question the validity or sufficiency of any of such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data. A field examination of the properties was not considered necessary for the purposes of this report.

Methodology and Procedures

The process of estimating reserves requires complex judgments and decision-making based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil, synthetic crude oil and natural gas reserves, and related future net cash flows, we consider many factors and make assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs

Estimates of reserves were prepared using standard geological and engineering methods generally accepted by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of June 2019).” Generally accepted methods for estimating reserves include volumetric calculations, material balance techniques, production decline curves, pressure transient analysis, analogy with similar reservoirs, and reservoir simulation. The method or combination of methods used is based on professional judgment and experience.

Discovered oil and natural gas reserves are generally only produced when they are economically recoverable. As such, oil and gas prices, and capital and operating costs have an impact on whether reserves will ultimately be produced. As required by SEC rules, reserves represent the quantities that are expected to be economically recoverable using existing prices and costs. Estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

The proved reserves estimates in this report were based upon 2019 first-of-the month fiscal average pricing using benchmark pricing. Oil prices were primarily based upon West Texas Intermediate at Cushing crude oil benchmark of USD$55.70 per barrel and a Brent crude oil benchmark of USD$63.09 per barrel. Specific pricing for each field was adjusted for historical quality and transportation cost differentials, and for currency exchange rates. The resulting adjusted price is referred to as the “realized price.” For total proved reserves in the Greater Kaybob Project, the estimated realized prices were CAD$62.13 per barrel of crude oil, CAD$1.86 per Mcf of natural gas, and CAD$34.97 per barrel of natural gas liquids. For total proved reserves in the Tupper Montney Project, the estimated realized prices were CAD$1.99 per Mcf of natural gas, and CAD$56.59 per barrel of natural gas liquids. For total proved reserves in the Hibernia Main and Hibernia South East Extension projects, the estimated realized price was CAD$84.31, while in the Terra Nova Project, the estimated realized price was CAD$83.84 per barrel of crude oil.

Generally, operations are subject to various levels of government controls and regulations. These laws and regulations may include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, that are subject to change from time to time. Current legislation is generally a matter of public record, and additional legislation or amendments that will affect reserves or when any such proposals, if enacted, might become effective generally cannot be predicted. Changes in government regulations could affect reserves or related economics. In the regions that are currently being evaluated we believe we have applied existing regulations appropriately.

McDANIEL

Murphy Estimates

Murphy has represented that estimated proved reserves attributable to the audited properties are based on SEC definitions. Murphy represents that its estimates of the reserves attributable to these properties represents approximately 43 percent of the total proved developed net reserves on a barrel of oil equivalent, BOE basis and 36 percent of the total proved undeveloped net reserves on a barrel of oil equivalent BOE basis of Murphy. These reserves are as follows, expressed in thousands of barrels (Mbbl) and thousands of barrels of oil equivalent (Mboe):

Murphy's estimate of Reserves as of December 31, 2019
Certain Canadian Fields Audited by McDaniel & Associates

Business Unit	Crude Oil (Mbbl)	Natural Gas (Mboe)	Natural Gas Liquids (Mboe)	Oil Equivalent (Mboe)
Working Interest Reserves (after royalties)				
Proved Developed Producing				
Greater Kaybob	6,586	4,361	773	11,720
Tupper Montney	-	161,448	669	162,117
East Coast Canada	16,292	1,998	-	18,290
Proved Developed Non-Producing				
Greater Kaybob	640	219	40	898
Tupper Montney	-	867	1	868
East Coast Canada	436	-	-	436
Proved Developed				
Greater Kaybob	7,225	4,580	813	12,619
Tupper Montney	-	162,315	670	162,985
East Coast Canada	16,728	1,998	-	18,726
Proved Undeveloped				
Greater Kaybob	17,294	6,059	1,104	24,457
Tupper Montney	-	97,661	235	97,896
East Coast Canada	2,583	67	-	2,650
Total Proved				
Greater Kaybob	24,519	10,639	1,917	37,074
Tupper Montney	-	259,976	905	260,881
East Coast Canada	19,311	2,064	-	21,375

Note: Gas is converted to oil equivalent using a factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent based on an energy equivalent basis. Of the Total Proved Natural Gas reserves estimated by Murphy above, 2,064 Mboe are attributed to fuel gas reserves in the East Coast Canada Business Unit, and 18,368 Mboe are attributed to fuel gas reserves in the Tupper Montney Project.

Reserves Audit Opinion

McDaniel has used all data, assumptions, procedures and methods that it considers necessary to prepare this report.

In our opinion, the information relating to estimated proved reserves of bitumen and synthetic crude oil contained in this opinion has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7 and 932-235-50-9 of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, and 1202(a) (1), (2), (3), (4), (5), (8) of Regulation S-K of the Securities and Exchange Commission.

We have examined the assumptions, data, methods procedures and proved reserves estimates prepared by Murphy. In our opinion, the proved reserves for the reviewed properties as estimated by Murphy are, in aggregate on the basis of equivalent barrels, reasonable because when compared to our estimates, or if we were to perform our own detailed estimates, reflect a difference of not more than plus or minus 10 percent.

The analyses of these properties, as reported herein, was conducted within the context of an audit of a distinct group of properties in aggregate as part of the total corporate level reserves. Extraction and use of these analyses outside of this context may not be appropriate without supplementary due diligence.

McDaniel is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over 60 years. McDaniel does not have any financial interest, including stock ownership, in Murphy. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Murphy.

This report was prepared by McDaniel & Associates Consultants Ltd. for the exclusive use of Murphy. It is not to be reproduced, distributed, or made available, in whole or in part to any person, company, or organization other than Murphy without the knowledge and consent of McDaniel & Associates Consultants Ltd. We reserve the right to revise any of the estimates provided herein if any relevant data existing prior to preparation of this report was not made available or if any data provided was found to be erroneous.

McDANIEL

If there are any questions, please contact Cam Boulton at (403) 218-8964 or Jared Wynveen directly at (403) 218-1397.

Sincerely,

McDANIEL & ASSOCIATES CONSULTANTS LTD.
APEGA PERMIT NUMBER: P3145

/s/ Cameron T. Boulton

Cameron T. Boulton, P. Eng.
Executive Vice President
January 23, 2020

/s/ Jared W. B. Wynveen

Jared W. B. Wynveen, P. Eng.
Executive Vice President
January 23, 2020

McDANIEL