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, 2021

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)**
9805 Katy Fwy, Suite G-200	**77024**
Houston, Texas	**(Zip Code)**
(Address of principal executive offices)	

(281) 675-9000
(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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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, 2021) – $2,144,310,114.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2022 was 154,492,604.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 11, 2022 have been incorporated by reference in Part III herein.

MURPHY OIL CORPORATION
2021 FORM 10-K
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PART I

Item 1. BUSINESS

Summary

Murphy Oil Corporation is a global oil and natural gas exploration and production company, with both Onshore and Offshore operations and properties. 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 exploration and production segments. The Company's corporate headquarters are located in Houston, Texas following relocation from El Dorado, Arkansas in 2020.

As part of the Company's underlying operations, the Company is continually monitoring its greenhouse gas emissions and impact on the environment as well as other social and environmental aspects of its business. See Sustainability on page 10.

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 31 through 48, 81 through 82, 110 through 125 and 128 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 produces crude oil, natural gas and natural gas liquids primarily in the U.S. and Canada and explores for crude oil, natural gas and natural gas liquids in targeted areas worldwide. The Company's management team, based in Houston, Texas, directs these activities.

During 2021, Murphy's principal 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 operations and production in 2021 were in the United States, Canada and Brunei. Murphy is in the process of winding down operations in Australia.

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 2021 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 167,356 barrels of oil equivalent per day, a decrease of 4.2% compared to 2020.

For further details on business execution, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" starting on page 32. For further details on 2021 production and sales volume see pages 41 to 42.

United States

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 95,600 barrels of crude oil and natural gas liquids per day and approximately 90 MMCF of natural gas per day in the U.S. in 2021. These amounts represented 90.1% of the Company's total worldwide oil and natural gas liquids and 24.4% of worldwide natural gas production volumes.

Offshore

During 2021, approximately 68% of total U.S. hydrocarbon production was produced at fields in the Gulf of Mexico, of which approximately 74% was derived from six fields, including Cascade/Chinook, Dalmatian, Kodiak, Marmalard, Neidermeyer, and St. Malo. Total average daily production in the Gulf of Mexico in 2021 was 64,900 barrels of crude oil and natural gas liquids and 61 MMCF of natural gas. At December 31, 2021, Murphy had total proved reserves for Gulf of Mexico fields of 152.3 million barrels of oil and natural gas liquids and 121.0 billion cubic feet of natural gas.

The Company has various operated and non-operated fields in the U.S. Gulf of Mexico. The most significant fields are St. Malo, Khaleesi, Mormont, Samurai, Dalmatian and Lucius. Khaleesi, Mormont and Samurai are currently in the development phase.

Onshore

The Company holds rights to approximately 133 thousand gross acres in South Texas in the Eagle Ford Shale unconventional oil and natural gas play. During 2021, approximately 32% of total U.S. hydrocarbon production was produced in the Eagle Ford Shale. Total 2021 production in the Eagle Ford Shale area was 30,670 barrels of oil and liquids per day and 28 MMCF per day of natural gas. At December 31, 2021, the Company's proved reserves for the U.S. Onshore business totaled 137.8 million barrels of liquids and 199.3 billion cubic feet of natural gas.

Canada

In Canada, the Company holds working interests in the following: (a) a dry natural gas area at Tupper Montney (100% owned), (b) Kaybob Duvernay (operated), (c) liquids Placid Montney (non-operated), and (d) two non-operated offshore assets – the Hibernia and Terra Nova fields offshore Newfoundland in the Jeanne d'Arc Basin.

Onshore

Murphy has approximately 142 thousand gross acres of Tupper Montney mineral rights located in northeast British Columbia. Daily production in 2021 in onshore Canada averaged 6,400 barrels of liquids and 278 MMCF of natural gas. Total onshore Canada proved liquids and natural gas reserves at December 31, 2021, were approximately 14.2 million barrels and 2.0 trillion cubic feet, respectively.

The Company currently has a commitment for 483 MMCFD of natural gas processing capacity to support production in the Tupper Montney through November 2040.

The Company holds 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 Company has approximately 310 thousand gross acres of Kaybob Duvernay and Placid Montney mineral rights.

Offshore

Murphy has a 6.5% working interest in Hibernia Main, a 4.3% working interest in Hibernia South Extension, and an 18% working interest at Terra Nova.

Oil production in 2021 was 3,765 barrels of oil per day for Hibernia.

During 2021, Terra Nova did not operate as asset integrity work to extend the project was being undertaken. The operator initially provided notice of abandonment in the first quarter of 2021, before a commercial resolution in the third quarter of 2021 led Murphy to acquire an additional 7.525% of working interest in a commercial settlement with the other partners. The Terra Nova asset life is now extended to an estimated date of 2032.

Total proved reserves for offshore Canada at December 31, 2021 were approximately 25 million barrels of liquids and 14.4 billion cubic feet of natural gas.

Australia

In Australia, the Company holds one offshore exploration permit; Murphy is not the operator. The permit does not have a drilling commitment.

Brazil

The Company holds an interest in nine 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, SEAM-M-505, SEAL-M-573, SEAL-M-575 and SEAL-M-637). ExxonMobil is the operator of the blocks. Murphy has a 20% working interest, ExxonMobil has a 50% working interest and Enauta Energia SA holds a 30% working interest.

Murphy has also farmed into 3 additional blocks in the Potiguar Basin (POT-M-857, POT-M-863, and POT-M-865) with a 30% working interest; Wintershall Dea is the operator. Subsequent to year end, Wintershall Dea announced that it will terminate all operations in Brazil and will close the office in Rio de Janeiro. Murphy will transition to operator.

Murphy's total acreage position in Brazil as of December 31, 2021 is approximately 2,453 thousand gross acres, offsetting several major discoveries. There are no well commitments.

Brunei

The Company has a working interest of 8.051% in Block CA-1 and a 30% working interest in Block CA-2; as of December 31, 2021, Block CA-2 is held for sale.

In CA-1, on November 23, 2017, the governments of 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.

In CA-2, in December 2014, the governmental authority approved the Gas Holding Area (GHA) for the Kelidang Cluster (KC) development. The consortium is presently carrying out pre-development engineering related to the KC development with the aim to achieve project sanction in 2023.

The CA-1 and CA-2 blocks cover 1.4 million and 157,602 gross acres, respectively. Five exploration wells have been drilled in Block CA-1 and seven exploration wells have been drilled in Block CA-2 as of the end of 2021.

Mexico

In March 2017, as part of Mexico's fourth phase, round one deepwater auction, Murphy was awarded Block 5. Murphy is the operator of the block with a 40% working interest. Block 5 is located in the deepwater Salinas Basin covering approximately 640 thousand 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. A further exploration well is planned for 2022.

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 Production Sharing Contracts (PSCs).

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 and the field Outline Development Plan was approved in August 2019. The Lac Da Trang (LDT) 1X exploration well, the last remaining commitment of the PSC, was completed in April 2019. The sanction of the LDV development is under review with PetroVietnam.

In Block 15-2/17, the Company is progressing study activity in anticipation of drilling an exploration commitment well by 2023.

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In Blocks 144 and 145, 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 of 3D seismic is tentatively scheduled for 2024.

Proved Reserves

Total proved reserves for crude oil, natural gas liquids and natural gas as of December 31, 2021 are presented in the following table.

	Proved Reserves			
	All Products	Crude Oil	Natural Gas Liquids	Natural Gas [4]
Proved Developed Reserves:	(MMBOE)	(MMBBL)		(BCF)
United States	**241.9**	**174.9**	**25.6**	**248.1**
Onshore	127.8	82.3	19.2	157.7
Offshore [1]	114.0	92.6	6.4	90.4
Canada	**176.8**	**16.0**	**2.8**	**947.7**
Onshore	168.7	8.6	2.8	943.9
Offshore	8.1	7.4	—	3.8
Other	**0.6**	**0.5**	**—**	**0.2**
Total proved developed reserves	**419.2**	**191.5**	**28.4**	**1,196.0**
Proved Undeveloped Reserves:				
United States	**101.6**	**80.0**	**9.5**	**72.2**
Onshore	43.2	29.9	6.3	41.6
Offshore [2]	58.4	50.1	3.2	30.6
Canada	**196.0**	**19.8**	**0.5**	**1,054.1**
Onshore	176.7	2.3	0.5	1,043.5
Offshore	19.3	17.6	—	10.6
Other	**0.1**	**0.1**	**—**	**—**
Total proved undeveloped reserves	**297.7**	**99.9**	**10.0**	**1,126.4**
Total proved reserves [3]	**716.9**	**291.5**	**38.4**	**2,322.3**

[1] Includes proved developed reserves of 16.2 MMBOE, consisting of 14.6 MMBBL oil, 0.6 MMBBL NGLs, and 5.4 BCF natural gas, attributable to the noncontrolling interest in MP GOM.
[2] Includes proved undeveloped reserves of 2.2 MMBOE, consisting of 2.0 MMBBL oil, 0.1 MMBBL NGLs, and 0.7 BCF natural gas, attributable to the noncontrolling interest in MP GOM.
[3] Includes proved reserves of 18.4 MMBOE, consisting of 16.6 MMBBL oil, 0.7 MMBBL NGLs, and 6.1 BCF natural gas, attributable to the noncontrolling interest in MP GOM.
[4] Includes proved natural gas reserves to be consumed in operations as fuel of 78.7 BCF and 74.0 BCF for the U.S. and Canada, respectively, with 1.7 BCF attributable to the noncontrolling interest in MP GOM.
[5] Totals within the tables may not add as a result of rounding.

Proved Reserves (Contd.)

Murphy Oil's 2021 total proved reserves and proved undeveloped reserves are reconciled from 2020 as presented in the table below:

(Millions of oil equivalent barrels) [1]	Total Proved Reserves	Total Proved Undeveloped Reserves
Beginning of year	714.9	304.1
Revisions of previous estimates	(52.9)	(61.7)
Extensions and discoveries	109.4	109.0
Conversions to proved developed reserves	—	(59.5)
Purchases of properties	7.4	5.8
Sale of properties	(0.7)	—
Production	(61.1)	—
End of year [2]	**716.9**	**297.7**

[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 18.4 MMBOE and 2.2 MMBOE for total proved and proved undeveloped reserves, respectively, attributable to the noncontrolling interest in MP GOM.
[3] Totals within the tables may not add as a result of rounding.

During 2021, Murphy's total proved reserves increased by 2.1 million barrels of oil equivalent (MMBOE). The increase in reserves principally relates to extensions of 90.7 MMBOE in Canada Onshore, 10.3 MMBOE in the Eagle Ford Shale, and 8.4 MMBOE in offshore U.S. Gulf of Mexico and East Canada as well as an acquisition of increased working interest in Canada Offshore, offset by negative price revisions in Tupper Montney from accelerated royalty incentive payouts due to higher commodity prices and 2021 production of 61.1 MMBOE.

Murphy's total proved undeveloped reserves at December 31, 2021 decreased 6.4 MMBOE from a year earlier. The proved undeveloped reserves reported in the table as extensions and discoveries during 2021 were predominantly attributable to three areas: the onshore Canada area of Tupper Montney, the Eagle Ford Shale in South Texas, and the U.S. Gulf of Mexico. 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 negative price revisions in Tupper Montney from accelerated royalty incentive payouts due to higher commodity prices. 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 and Tupper Montney.

The Company spent approximately $473 million in 2021 to convert proved undeveloped reserves to proved developed reserves. The Company expects to spend approximately $700 million in 2022, $371 million in 2023 and $295 million in 2024 to move currently undeveloped proved reserves to the developed category. The anticipated level of spending in 2022 primarily includes drilling and development in the Gulf of Mexico, Eagle Ford Shale and Tupper Montney areas.

At December 31, 2021, proved reserves are included for several development projects, including oil developments at the Eagle Ford Shale in South Texas, deepwater Gulf of Mexico; and Kaybob Duvernay in onshore Canada; as well as natural gas developments at Tupper Montney in onshore Canada. Total proved undeveloped reserves associated with various development projects at December 31, 2021 were approximately 297.7 MMBOE, which represent 42% 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 currently operates deepwater fields in the Gulf of Mexico that have two undeveloped locations that exceed this five-year window. Total reserves associated with the two locations amount to approximately 0.4% of the Company's total proved reserves at year-end 2021. The development of certain reserves extends beyond five years due to limited well slot availability, 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 business units 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.

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 20 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 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 2021, 93.2% of the Proved reserves were audited by third-party auditors and they were found to be within the acceptable 10% tolerance by each of the third-party firms. Murphy engaged both Ryder Scott Company, L.P. (Ryder Scott) and McDaniel & Associates Consultants Ltd. (McDaniel) to perform a reserves audit of 47.9% and 45.3% of the Company’s total proved reserves, respectively.

Each significant exploration and production business unit 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 business units 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.

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

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 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 internal 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 112 through 119 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, 2021 are shown on pages 41 through 43 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 38 of this Form 10-K report.

Supplemental disclosures relating to oil and natural gas producing activities are reported on pages 110 through 126 of this Form 10-K report.

Acreage and Well Count

At December 31, 2021, 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	26	25	135	122
	Gulf of Mexico	37	17	602	310	639	327
Total United States		146	114	628	335	774	449
Canada	Onshore	137	106	314	221	451	327
	Offshore	101	11	28	1	129	12
Total Canada		238	117	342	222	580	339
Mexico		—	—	636	254	636	254
Brazil		—	—	2,453	568	2,453	568
Australia		—	—	482	241	482	241
Brunei		—	—	1,604	164	1,604	164
Vietnam		—	—	7,324	4,571	7,324	4,571
Spain		—	—	8	1	8	1
Totals		384	231	13,477	6,356	13,861	6,587

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

Scheduled expirations in 2022 include 4,521 thousand net acres in Vietnam (seeking extensions), 46 thousand net acres in the Gulf of Mexico, 35 thousand net acres in onshore Canada, and 30 thousand net acres in Brunei.

Acreage currently scheduled to expire in 2023 include 241 thousand net acres in Australia, 75 thousand net acres in Brazil, 35 thousand net acres in onshore Canada, 16 thousand net acres in the Gulf of Mexico, and 1 thousand net acres in Spain.

Scheduled expirations in 2024 include 47 thousand net acres in the Gulf of Mexico and 17 thousand net acres in onshore Canada.

Acreage and Well Count (Contd.)

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, 2021.

		Oil Wells		Natural Gas Wells	
		Gross	Net	Gross	Net
Country					
United States	Onshore	1,108	912	25	4
	Gulf of Mexico	62	30	16	9
Total United States		1,170	942	41	13
Canada	Onshore	16	11	386	321
	Offshore	50	5	—	—
Total Canada		66	16	386	321
Totals		1,236	958	427	334

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
2021								
Exploration	**—**	**0.1**	**—**	**—**	**—**	**—**	**—**	**0.1**
Development	**27.9**	**—**	**14.6**	**—**	**—**	**—**	**42.5**	**—**
2020								
Exploration	—	0.4	0.7	—	—	—	0.7	0.4
Development	21.5	—	8.9	—	—	—	30.4	—
2019								
Exploration	0.6	—	—	—	—	—	0.6	—
Development	84.6	—	18.6	—	—	—	103.2	—

Murphy's drilling wells in progress at December 31, 2021 are shown in the following table. The year-end well count includes wells awaiting various completion operations.

		Exploration		Development		Total	
		Gross	Net	Gross	Net	Gross	Net
Country							
United States	Onshore	—	—	21.0	10.6	21.0	10.6
	Gulf of Mexico	—	—	5.0	2.0	5.0	2.0
Canada	Onshore	—	—	13.0	12.1	13.0	12.1
	Offshore	—	—	—	—	—	—
Brazil		1.0	0.2	—	—	1.0	0.2
Totals		1.0	0.2	39.0	24.7	40.0	24.9

Sustainability

Environment and Climate Change

We understand that our industry, and the use of our products, create emissions – which raise climate change concerns. At the same time, access to affordable, reliable energy is essential to improving the world's quality of life and the functioning of the global economy. We believe that as the energy economy transitions, oil and natural gas will continue to play a vital role in the long-term energy mix.

We are committed to reducing our GHG emissions, and focused on understanding and mitigating our climate change risks. To guide our climate change strategy, Murphy has adopted a climate change position, and we are setting meaningful emissions goals. In 2021, we endorsed the goal of eliminating routine flaring by 2030, under the current World Bank definition of routine flaring. This adds to the Company's previously established greenhouse gas (GHG) emissions intensity reduction target of 15% to 20% by 2030 from our 2019 level, excluding our discontinued and divested Malaysia operations.

Murphy recognizes that emissions are only one element of our total environmental footprint. Protecting natural resources is also an important factor in our overall sustainability efforts. See our discussion of Climate Change and Emissions on page 48.

Further, we are subject to various international, foreign, national, state, provincial and local environmental, health and safety laws and regulations, including related to the generation, storage, handling, use, disposal and remediation of petroleum products, wastewater and hazardous materials; the emission and discharge of such materials to the environment, including GHG emissions; wildlife, habitat and water protection; the placement, operation and decommissioning of production equipment; and the health and safety of our employees, contractors and communities where our operations are located.

U.S. Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). CERCLA and similar state statutes impose joint and several liability, without regard to fault or legality of the conduct, on current and past owners or operators of a site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Although CERCLA generally exempts "petroleum" from regulation, in the course of our operations, we may and could generate wastes that may fall within CERCLA's definition of hazardous substances and may have disposed of these wastes at disposal sites owned and operated by others.

Water discharges. The U.S. Clean Water Act (CWA) and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, into regulated waters. The U.S. Oil Pollution Act (OPA) imposes certain duties and liabilities on the owner or operator of a facility, vessel or pipeline that is a source or that poses the substantial threat of an oil discharge, or the lessee or permittee of the area in which a discharging offshore facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. The OPA also requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill.

U.S. Bureau of Ocean Energy Management (BOEM) and the U.S. Bureau of Safety and Environmental Enforcement (BSEE) requirements. BOEM and BSEE have regulations applicable to lessees in federal waters that impose various safety, permitting and certification requirements applicable to exploration, development and production activities in the Gulf of Mexico, and also require lessees to have substantial U.S. assets and net worth or post bonds or other acceptable financial assurance that the regulatory obligations will be met.

These include, in the Gulf of Mexico, well design, well control, casing, cementing, real-time monitoring, and subsea containment, among other items. Under applicable requirements, BOEM evaluates the financial strength and reliability of lessees and operators active on the Outer Continental Shelf, including the Gulf of Mexico. If the BOEM determines 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.

Air emissions and climate change. The U.S. Clean Air Act (CAA) and comparable state laws and regulations govern emissions of various air pollutants through the issuance of permits and other authorization requirements. Since 2009, the U.S. Environmental Protection Agency (EPA) has been monitoring and regulating GHG emissions, including carbon dioxide and methane, from certain sources in the oil and natural gas sector due to their association with climate change. In addition, international climate efforts, including the 2015 "Paris Agreement" and the 2021 UN Framework Convention on Climate Change (COP26), have resulted in commitments from many countries to reduce GHG emissions and have called for parties to eliminate certain fossil fuel subsidies and pursue further action on non-carbon dioxide GHGs.

Murphy is currently required to report GHG 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, GHG 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.

Endangered and threatened species. The U.S. Endangered Species Act was established to protect endangered and threatened species. If a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act, and marine mammals under the Marine Mammal Protection Act.

As noted above, Murphy is subject to various laws and regulatory regimes governing similar matters in other jurisdictions in which it operates. More specifically, Murphy's operations in Canada are subject to and conducted under Canadian laws and regulations that address many of the same environmental, health and safety issues as those in the U.S., including, without limitation, pollution and contamination, air quality and emissions, water discharges, and other health and safety concerns.

Health and Safety

Murphy's commitment to safety is strong, and so are our actions to protect our workforce and communities. Our employees are our most valuable asset. Murphy strives to achieve incident-free operations through continuous improvement processes managed by the Company's Health, Safety, Environment (HSE) Management System (HSE-MS), which engages all personnel, contractors and partners associated with Murphy operations and facilities, and provides a consistent method for integrating HSE concepts into our procedures and programs. We work hard to build a culture of safety across our organization, with regular training, exercise drills and key targeted safety initiatives.

Response to COVID-19. During the COVID-19 pandemic, we have taken a proactive approach and adopted strict protocols to protect our employees and their families, contractors and the communities in which we work from the virus. Our response program continues to be led by our Incident Management Team (IMT), under the guidance of our Crisis Management Team (CMT), leveraging the advice and recommendations of infectious disease experts and establishing safety protocols for all workers. We also developed a COVID-19 tracking app, providing executives with real-time information on infection rates and close contacts, in order to make decisions regarding our COVID-19 response.

Safety. The Company is subject to the requirements of the U.S. 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. In Canada, the Company is subject to Federal OH&S Legislation, the provincially-administered Occupational Health and Safety Act (Alberta), the Workers Compensation Act (British Columbia), and WHMIS - the Workplace Hazardous Materials Information System.

Human Capital Management

Employees

At Murphy, we believe in providing energy that empowers people, and that is what our 696 employees do every day. As of December 31, 2021, we had 408 office-based employees and 288 field employees, all of whom are guided by our mission, vision, values and behaviors. Together with the Executive Leadership Team, the Vice President of Human Resources and Administration, who reports directly to our CEO, is responsible for developing and executing our human capital management strategy. This includes the attraction, recruitment, development and engagement of talent to deliver on our strategy, the design of employee compensation, health and welfare benefits, and talent programs. We focus on the following factors in order to implement and develop our human capital strategy:

- Employee Compensation Programs
- Employee Performance and Feedback
- Talent Development and Training
- Diversity, Equity and Inclusion
- Health and Welfare Benefits

The Board of Directors receives related updates from management on a regular cadence including the review of compensation, benefits, succession and talent development, and diversity, equity and inclusion.

Employee Compensation Programs

Our purpose, to empower people, includes tying a portion of our employees pay to performance in a variety of ways, including incentive compensation and merit-based bonus programs, while maintaining the best interest of shareholders. We benchmark for market practices, and regularly review our compensation against the market to ensure it remains competitive to attract and retain the best talent. We believe our current practices align our employees' compensation with the interests of our shareholders, and support our focus on cash flow generation, capital return and environmental stewardship. For further detail on the Company's compensation framework please see the Compensation Discussion and Analysis section of the forthcoming Proxy Statement relating to the Annual Meeting of Stockholders on May 11, 2022.

Employee Performance and Feedback

We are committed to efforts to enhance our employees' professional growth and development through feedback that utilizes our internal performance management system (Murphy Performance Management - MPM). The purpose of Murphy's MPM process is to show our commitment to the development of all employees and to better align rewards with Company and individual performance. The goals of the MPM process are the following:

- Drive behavior to align with the Company's mission, vision, values and behaviors
- Develop employee capabilities through effective feedback and coaching
- Maintain a process that is consistent throughout the organization to measure employee performance and is tied to Company and shareholder interests

All employees' performance is evaluated at least annually through self-assessments that are reviewed in discussions with supervisors. Employees' performance is evaluated on various key performance indicators set annually, including behaviors that support our mission, vision, values and an assessment conducted by the employees' direct supervisor.

Talent Development and Training

Employees are able to participate in continuous training and development, with the goal of equipping them for success and providing increased opportunities for growth at Murphy. Through our digital platform, My Murphy Learning, employees can access self-directed courses, external articles and videos that cover topics such as business, technology and productivity. We also administer mandatory compliance training for our employees through My Murphy Learning, with a 100% completion rate. Further, we strive to empower our leadership, so we sponsor several programs to address career advancement for emerging leaders and executives. Plus, we provide a tuition reimbursement program for those who choose to acquire additional knowledge to increase their effectiveness in their present position or to prepare for career advancement. Murphy holds internal technical ideas forums each year designed to share best practice and technical advances across the Company, including safety and environmental topics.

We encourage employee engagement and solicit feedback through internal surveys and our employee driven Ambassador program to gain insights into workplace experiences. Employees are provided opportunities to raise suggestions and collaborate with leadership to improve programs and increase their alignment with Murphy’s mission, vision, values and behaviors.

To ensure that our human capital investment and development programs are effective, we track voluntary turnover. This data is shared on a regular basis with our Executive Leadership Team, who use it in addition to other pertinent data to develop our human capital strategy. In 2021, our voluntary employee turnover rate was 5.7%.

Health and Welfare Benefits

We believe that doing our part to aid in maintaining the health and welfare of our employees is a critical element in Murphy achieving success. As such, we provide our employees and their families with a comprehensive set of subsidized benefits that are competitive and aligned to Murphy’s mission, vision, values and behaviors. In 2021, we further enhanced our benefit offerings including by implementing a vacation roll over policy, expanding dental coverage and increasing the number of weeks fully paid for short term disability. We also believe that the well-being of our employees is enhanced when they can give back to their local communities or charities either through the company “Impact – Murphy Makes a Difference” program or on their own and receive a company match for donations.

In addition, we offer an Employee Assistance Program (EAP) that provides confidential assistance to employees and their immediate family members for mental and physical well-being, as well as legal and financial issues. We also maintain an Ethics Hotline that is available to all our employees to report, anonymously if desired, any matter of concern. Communications to the hotline, which is facilitated by an independent third party, are routed to appropriate functions, Human Resources, Law or Compliance, for investigation and resolution.

Diversity, Equity and Inclusion

We are committed to fostering work environments that value diversity, equity, and inclusion (DE&I). This commitment includes providing equal access to and participation in programs and services without regard to race, creed, religion, color, national origin, disability, sex (including pregnancy), sexual orientation, gender identity, veteran status, age or stereotypes or assumptions based thereon. We also support interest-based groups such as sports, hobbies and charity volunteering. We welcome our employees’ differences, experiences and beliefs, and we are investing in a more productive, engaged, diverse and inclusive workforce. The Board of Directors receives DE&I updates on Demographic Data, Strategic Partnerships, Recruiting Strategies and Programs from management on a regular cadence.

Throughout 2021, we focused on creating a unified engagement program to build awareness and encourage open and respectful discussions. We launched a video series where employees were invited to record short videos to share their ideas and experiences on what Diversity, Equity and Inclusion means to them. Under the sponsorship of our Vice President, Human Resources and Administration, we encourage employee engagement and continuous feedback on our programs through our employee-level DE&I committee. The committee, which consists of employees at various levels in the organization, promotes a culture of DE&I. In addition, our Board has had at least one woman member for over 30 years, and currently includes three women directors. Our Nominating and Governance Committee is actively focused on issues of DE&I as part of its overall mandate. Also, our Board expanded the focus of the Health, Safety and Environment Committee to include Corporate Responsibility.

Women Representation (US and International)	**2021**
Executive and Senior Level Managers	12 %
First- and Mid-Level Managers	18 %
Professionals	34 %
Other (Administrative Support and Field)	7 %
Total	**21 %**

Minorities [1] Representation (US-Based Only)	**2021**
Executive and Senior Level Managers	18 %
First- and Mid-Level Managers	22 %
Professionals	34 %
Other (Administrative Support and Field)	31 %
Total	**30 %**

[1] As defined by the U.S. Equal Employment Opportunity Commission (EEOC).

We believe that it is important we attract employees with diverse backgrounds where we operate and are focusing on increasing the number of women and minorities in our workforce ensuring a vibrant talent pipeline.

Environmental, Social and Governance (ESG) Disclosure

We publish an annual sustainability report according to internationally recognized ESG reporting frameworks and standards, including Sustainability Accounting Standards Board (SASB), Task Force on Climate-related Financial Disclosures (TCFD), Global Reporting Initiative (GRI): Core option and IPIECA.

As this is an area of continual improvement across our industry, we strive to update our disclosures in line with operating developments and with emerging best practice ESG reporting standards. In 2021, we published our third annual sustainability report, located on the Company's website.

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, or incorporated into, 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

The Company faces risks in the normal course of business and through global, regional, and local events that could have an adverse impact on its reputation, operations, and financial performance. The Board of Directors exercises oversight of the Company's enterprise risk management program, which includes strategic, operational and financial matters, as well as compliance and legal risks. The Board of Directors receives updates annually on the risk management processes.

The following are some important factors that could cause the Company's actual results to differ materially from those projected in any forward-looking statements. If any of the events or circumstances described in any of the following risk factors occurs, our business, results of operations and/or financial condition could be materially and adversely affected, and our actual results may differ materially from those contemplated in any forward-looking statements we make in any public disclosures.

Price Risk Factors

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

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. Many of the factors influencing prices of crude oil and natural gas are beyond our control. These factors include:

- the occurrence or threat of epidemics or pandemics, such as the outbreak of coronavirus disease 2019 (COVID-19), or any government response to such occurrence or threat which may lower the demand for hydrocarbon fuels;
- worldwide and domestic supplies of, and demand for, crude oil, natural gas liquids and natural gas;
- the ability of the members of OPEC and certain non-OPEC members, for example, Russia, to agree to and maintain production levels;
- the production levels of non-OPEC countries, including, amongst others, production levels in the shale plays in the United States;
- the level of drilling, completion and production activities by other exploration and production companies, and variability therein, in response to market conditions;
- political instability or armed conflict in oil and natural gas producing regions;
- changes in weather patterns and climate, including as a result of climate change;
- natural disasters such as hurricanes and tornadoes, including as a result of climate change;
- the price, availability and the demand for and of alternative and competing forms of energy, such as nuclear, hydroelectric, wind or solar;
- the effect of conservation efforts and focus on climate-change;
- technological advances affecting energy consumption and energy supply;
- increased activism against, or change in public sentiment for, oil and gas exploration, development, and production activities and considerations including climate change and the transition to a lower carbon economy;
- domestic and foreign governmental regulations and taxes, including further legislation requiring, subsidizing or providing tax benefits for the use of alternative energy sources and fuels; and
- general economic conditions worldwide.

In 2021, a combination of the global availability of vaccines and a relaxation of certain government-imposed lockdowns in response to the ongoing coronavirus disease 2019 (COVID-19) pandemic has led to an improving global economic outlook and subsequently increased demand for oil and gas. Several COVID-19 variants, such as Delta and Omicron, temporarily created uncertainty in the outlook; however, vaccines remained effective and therefore demand for oil and gas has remained resilient in the second half of 2021 and early 2022. The demand resilience has revealed an oil supply shortage, and hence is applying upward pressure to current and future oil and gas prices in early 2022.

The OPEC+ group of oil producing countries (OPEC+) continues to target increasing supply by 0.4 million barrels per day (bpd) a month, with aims to fully phase out prior cuts by September 2022, at the current rate of OPEC+ supply increases. In 2020, OPEC+ cut production by 10 million bpd following the COVID-19 demand reduction. It has gradually reinstated supply so that the curtailments were approximately 5.8 million bpd at the end of 2021. However, some members of the OPEC+ are not meeting their commitments to reinstate supply..

West Texas Intermediate (WTI) crude oil prices averaged $68 per barrel in 2021, compared to $39 in 2020, $57 in 2019, and $65 in 2018. The closing price for WTI at the end of 2021 was $72 per barrel, reflecting a 52% increase from the price at the end of 2020. As of close on February 24, 2022, the NYMEX WTI forward curve price for the remainder of 2022 and 2023 were $86.31 and $77.72 per barrel, respectively. The current futures forward curve indicates that prices may continue at or near current prices for an extended time. 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 WTI prices. The most common crude oil indices used to price the Company’s crude include WTI Houston (MEH), Heavy Louisiana Sweet (HLS), Mars and Brent.

The average New York Mercantile Exchange (NYMEX) natural gas sales price was $3.84 per million British Thermal Units (MMBTU) in 2021, compared to $1.99 in 2020, $2.52 in 2019, and $3.12 in 2018. The closing price for NYMEX natural gas as of December 31, 2021 was $3.72 per MMBTU. The Company also has some limited exposure to the Canadian benchmark natural gas price, AECO, which averaged US$2.89 per MMBTU in 2021. The closing price for AECO as of December 31, 2021 was US$3.20 per MMBTU. The Company has entered into certain forward fixed price contracts as detailed in the Outlook section on page 54 and certain variable netback contracts providing exposure to Malin, Dawn and other locations.

Lower prices, should they occur, will materially and adversely affect our results of operations, cash flows and financial condition. Lower oil and natural gas prices could reduce the amount of oil and natural gas that the Company can economically produce, resulting in a reduction in the proved oil and natural gas reserves we could recognize, which could impact the recoverability and carrying value of our assets. The Company cannot predict how changes in the sales prices of oil and natural gas will affect the results of operations in future periods. The Company has 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.

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, as a result of low oil and gas prices, 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.

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

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.

In 2021, the Company entered into collar contracts. Under the collar contracts, which also mature monthly, the Company purchased put options and sold call options with no net premiums paid to or received from counterparties. Upon maturity, collar contracts require payments by the Company if the NYMEX average closing price is above the ceiling price or payments to the Company if the NYMEX average closing price is below the floor price.

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

Operational Risk Factors

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 major integrated oil companies, private equity investors and independent producers of oil and natural gas, and state-owned foreign oil companies. Many of the major integrated and state-owned 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. Within the industry, Murphy competes for, among other things, valuable acreage positions, exploration licenses, drilling equipment and talent.

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 hole expense, which may have adverse effects on, and create volatility for, the Company's results of operations. The Company's strategy is to participate in three to five exploration wells per year. In 2021, the Company drilled a successful exploration well in Brunei (Jagus Subthrust) and participated in one unsuccessful (non-commercial) well in the U.S. Gulf of Mexico. The Cutthroat well in Brazil, originally planned for 2021, will now be drilled in early 2022 due to permitting delays. The Company has budgeted $75 million for its 2022 exploration program, which includes the Cutthroat well in Brazil, the operated well in Mexico (Tulum), as well as a non-operated well in Brunei.

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.

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 110 through 119 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. In 2021, 93.2% of the Proved reserves were audited by third-party auditors.

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, 2021, and including noncontrolling interests, approximately 34% of the Company's crude oil and condensate proved reserves, 26% of natural gas liquids proved reserves and 49% 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 124 and 125 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.

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 2021, approximately 24% of the Company's total production was at fields operated by others, while at December 31, 2021, approximately 15% 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 business is subject to operational hazards, physical security risks and risks normally associated with the exploration and production of oil and natural gas, which could become more significant as a result of climate change.

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 is subject to numerous environmental, health and safety laws and regulations, and such existing and any potential future laws and regulations may result in material liabilities and costs.

The Company's operations are subject to various international, foreign, national, state, provincial, and local environmental, health and safety laws and regulations, including related to the generation, storage, handling, use, disposal and remediation of petroleum products, wastewater and hazardous materials; the emission and discharge of such materials to the environment, including greenhouse gas emissions; wildlife, habitat and water protection; the placement, operation and decommissioning of production equipment; and the health and safety of our employees, contractors and communities where our operations are located. These laws and regulations are subject to frequent change and have tended to become stricter over time. They can impose permitting and financial assurance obligations, as well as operational controls and/or siting constraints on our business, and can result in additional capital and operating expenditures.

Murphy also could be subject to strict liability for environmental contamination in various jurisdictions where it operates, 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 investigate, 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.

It is possible in the future certain regulatory bodies such as the Railroad Commission of Texas may enact regulation that bans or reduces flaring for US Onshore operations. Compliance with such regulations could result in capital investment which would reduce the Company's net cash flows and profitability.

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. Texas law imposes permitting, disclosure, disposal and well construction requirements on hydraulic fracturing operations, as well as public disclosure of certain information regarding the components used in the hydraulic fracturing process. Regulations in the provinces of British Columbia and Alberta also govern various aspects of hydraulic fracturing activities under their jurisdictions. It is possible that Texas, other states in which we may conduct fracturing in the future, the U.S., Canadian provinces and certain municipalities may 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 addition, BOEM and BSEE have regulations applicable to lessees in federal waters that impose various safety, permitting and certification requirements applicable to exploration, development and production activities in the Gulf of Mexico, and also require lessees to have substantial U.S. assets and net worth or post bonds or other acceptable financial assurance that the regulatory obligations will be met. These include, in the Gulf of Mexico, well design, well control, casing, cementing, real-time monitoring, and subsea containment, among other items. Under applicable requirements, BOEM evaluates the financial strength and reliability of lessees and operators active on the OCS. If the BOEM determines 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 addition, various executive orders by the current presidential administration and the Department of Interior over the course of 2021 regarding a temporary suspension of normal-course issuance of permits for fossil fuel development on federal lands and a pause on new oil and natural gas leases on public lands and offshore waters, and the Secretary of Interior's related review of permitting and leasing practices, could adversely impact Murphy's operations. For further details, see See "Risk Factors – General Risk Factors – Murphy's operations and earnings have been and will continue to be affected by domestic and worldwide political developments."

We face various risks associated with increased activism against, or change in public sentiment for, oil and gas exploration, development, and production activities and sustainability considerations, including climate change and the transition to a lower carbon economy.

Opposition toward oil and gas drilling, development, and production activity has been growing globally. Companies in the oil and gas industry are often the target of activist efforts from both individuals and non-governmental organizations and other stakeholders regarding safety, human rights, climate change, environmental matters, sustainability, and business practices. Anti-development activists are working to, among other things, delay or cancel certain operations such as offshore drilling and development.

Activism may continue to increase regardless of whether the current presidential administration in the U.S. is perceived to be following, or actually follows, through on the current president's campaign commitments to promote decreased fossil fuel exploration and production in the U.S, including as a result of the administration's environmental and climate change executive orders described earlier in this 10-K. Our need to incur costs associated with responding to these initiatives or complying with any resulting new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations. In addition, a change in public sentiment regarding the oil and gas industry could result in a reduction in the demand for our products or otherwise affect our results of operations or financial condition.

Financial Risk Factors

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. As of December 31, 2021, the Company had no outstanding borrowings under the RCF.

However, in the event the RCF was drawn, amounts drawn under the RCF may bear interest in relation to 1-month, 2-month, 3-month and 6-month 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. Some USD LIBOR tenors (overnight, 1-month, 3-month, 6-month and 12-month) will continue to be published until June 30, 2023, but U.S. regulators have published guidance instructing banks to cease entering into new contracts referencing USD-LIBOR no later than December 31, 2021. While methodologies to transition existing agreements that depend on LIBOR as a reference rate are being developed, 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 an adverse effect on our earnings and cash flows.

In March 2020, the Federal Reserve Bank of New York began publishing the Secured Overnight Financing Rate (SOFR) and associated indices. However, SOFR is fundamentally different from USD LIBOR for two key reasons. First, SOFR is a secured rate, while LIBOR is an unsecured rate. Second, SOFR is an overnight rate, while USD LIBOR represents interbank funding over different maturities. As a result, there can be no assurance that SOFR will perform in the same way as LIBOR would have at any time, including, without limitation, as a result of changes in interest and yield rates in the market, market volatility or global or regional economic, financial, political, regulatory, judicial or other events. For example, since publication of SOFR began on April 3, 2018, daily changes in SOFR have, on occasion, been more volatile than daily changes in comparable benchmark or other market rates.

In 2021, the Company undertook several actions to reduce overall debt. See Note G – Financing Arrangements and Debt for information regarding the Company's outstanding debt as of December 31, 2021.

The Company's ability to obtain additional financing is 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.

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 L – 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. In 2021 and at the start of 2022, this scenario of higher costs for goods and services in the oil and gas natural gas industry is being observed. In early 2022, the pressure of rising prices and demand for services has begun affecting the cost of goods and services in the oil and natural gas industry. Murphy has a dedicated procurement department focused on managing supply chain and input costs. Murphy also has certain transportation, processing and production handling services costs fixed through long-term contracts and commitments and therefore is partly protected from increasing price of services. However, from time to time, Murphy will seek to enter new commitments, exercise options to extend contracts and retender contracts for rigs and other industry services which could expose Murphy to the impact of higher prices.

The Company is exposed to credit risks associated with (i) sales of certain of its products to customers, (ii) joint venture partners and (iii) other counterparties.

Murphy is exposed to credit risk in three principle areas:

• Accounts receivable credit risk from selling its produced commodity to customers;

• Joint venture partners related to certain oil and natural gas properties operated by the Company. These joint venture partners may not be able to meet their financial obligation to pay for their share of capital and operating costs as they become due; and

• Counterparty credit risk related to forward price commodity hedge contracts to protect the Company's cash flows against lower oil and natural gas prices

To mitigate these risks the Company:

• Actively monitors the credit worthiness of all its customers, joint venture partners, and forward commodity hedge counterparties;

• Given the inherent credit risks in a cyclical commodity price business, the Company has increased the focus on its review of joint venture partners, the magnitude of potential exposure, and planning suitable actions should a joint venture partner fail to pay its share of capital and operating expenditures.

The inability of a purchaser of the Company's produced commodity, a joint venture partner of the Company, or counterparty in a forward price commodity hedge to meet their respective payment obligations to the Company could have an adverse effect on Murphy's future earnings and cash flows.

General Risk Factors

We face various risks related to health epidemics, pandemics and similar outbreaks, which may have material adverse effects on our business, financial position, results of operations and/or cash flows.

As the COVID-19 pandemic has evolved from its emergence in early 2020, so has its global impact. Our business has been affected in various ways, including in our results of operations. In 2020 the spread of COVID-19 led to disruption in the global economy and weakness in demand in crude oil, natural gas liquids and natural gas, which applied downward pressure on global commodity prices. In 2021, a combination of the global availability of vaccines and a relaxation of certain government-imposed lockdowns in response to the ongoing COVID-19 pandemic led to an improving global economic outlook and subsequently increased demand for oil and gas. Several COVID-19 variants, such as Delta and Omicron, temporarily created uncertainty in the outlook; however, vaccines remained effective and therefore demand for oil and gas has remained resilient in the second half of 2021 and early 2022.

The unpredictable nature of pandemics can therefore create volatility in commodity prices, hence see Risk Factors, "Price Risk Factors – Volatility in the global prices of crude oil, natural gas liquids and natural gas can significantly affect the Company's operating results."

If significant portions of our workforce are unable to work effectively, including because of illness, quarantines, government actions, facility closures or other restrictions in connection with the COVID-19 or other pandemic, our operations will likely be impacted and decrease our ability to produce, oil, natural gas liquids and natural gas. We may be unable to perform fully on our commitments and our costs may increase as a result of the COVID-19 outbreak. These cost increases may not be fully recoverable or adequately covered by insurance.

The COVID-19 or other pandemic could also cause disruption in our supply chain; cause delay, or limit the ability of vendors and customers to perform, including in making timely payments to us; and cause other unpredictable events.

We continue to work with our stakeholders (including customers, employees, suppliers, financial and lending institutions and local communities) to address this global pandemic responsibly. We continue to monitor the situation, to assess further possible implications to our business, supply chain and customers, and to take actions in an effort to mitigate adverse consequences. The Company continues to exercise financial discipline in managing costs and capital expenditures.

We cannot predict the ongoing impact of the COVID-19 or other pandemic. The extent to which the COVID-19 or other health pandemics or epidemics may impact our results will depend on future developments, including, among other factors, the duration and spread of the virus and its variants, availability, acceptance and effectiveness of vaccines along with related travel advisories, quarantines and restrictions, the recovery time of the disrupted supply chains and industries, the impact of labor market interruptions, and the impact of government interventions.

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

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct exploration, development, and production activities. We are no exception to this trend. As a company, 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 internally and externally, and conduct many other business activities.

Maintaining the security of our technology and preventing breaches is critical to our business operation. We rely on our information systems to protect and secure intellectual property, strategic plans, customer information, and personally identifiable information, such as employee information.

A successful or undetected cyberattack has the potential to halt business operations, impair our reputation, weaken our competitive advantage, and / or adversely impact our financial condition. Given the increasing global threats from cybercrime, the Company's approach to mitigate cybersecurity risk focuses on three key elements:

• People - Security awareness education and readiness-testing throughout the year for employees and contractors;

• Process - Incorporating "cyber awareness" in our day to day processes and maturing key controls such as recurring internal and external cyber risk assessments, physical and digital asset protection, and security vulnerability remediation via preventative and detective measures; and

• Technology - Investing in industry aligned security technology and threat intelligence capabilities.

As the sophistication of cyber threats continues to evolve, we may be required to dedicate additional resources to continue to modify or enhance our security measures, or to investigate and remediate any vulnerabilities to cyber-attacks.

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

From time to time, some governments intervene in the market for crude oil and natural gas produced in their countries through such actions as setting prices, determining rates of production, and controlling who may buy and sell the production.

Murphy is exposed to regulation, legislation and policies enacted by the federal government. As an example, following the election and inauguration of current president in January 2021, the U.S. Secretary of the Interior issued Order No. 3395 on January 20, 2021. This order served to potentially impact the timing of issuance of oil and gas leases, lease amendments and extension, and drilling permits on federal lands and offshore waters. However, following this notice, the Department of Interior has continued to approve permits and Murphy has not experienced a delay in project approvals. An extension or permanency of this regime could impact the options available to Murphy for future development, reserves available for production and hence future cash flows and profitability. In the event leasing delays or cancellations alter Murphy's plans in the Gulf of Mexico, the Company believes it will be able to re-focus activities and allocate capital to other areas. The Company does not hold any onshore federal lands in the U.S.

In addition, the current presidential administration has pursued other initiatives related to environmental, health and safety standards applicable to the oil and gas industry. These include an executive order in January 2021 that directed the Secretary of the Interior to halt indefinitely new oil and natural gas leases on federal lands and offshore waters pending a since-completed review by the Secretary of the Interior of federal oil and gas permitting and leasing practices; however, a June 2021 preliminary injunction in the U.S. District Court for the Western District of Louisiana barred the current presidential administration from implementing the pause in new federal oil and gas leases. This executive order also set forth other initiatives and goals, including procurement of carbon pollution-free electricity, elimination of fossil fuel subsidies, a carbon pollution-free power sector by 2035 and a net-zero emissions U.S. economy by 2050. Another executive order from January 2021 called for a climate change-focused review of regulations and other executive actions promulgated, issued or adopted during the prior Presidential administration.

These actions and any future changes to applicable environmental, health and safety, regulatory and legal requirements promulgated by the current presidential administration and Congress may restrict our access to additional acreage and new leases in the U.S. Gulf of Mexico or lead to limitations or delays on our ability to secure additional permits to drill and develop our acreage and leases or otherwise lead to limitations on the scope of our operations, or may lead to increases to our compliance costs. The potential impacts of these changes on our future consolidated financial condition, results of operations or cash flows cannot be predicted.

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. As of December 31, 2021, 0.1% of the Company's proved reserves, as defined by the SEC, were located in countries other than the U.S. and Canada.

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 and other similar anti-corruption compliance statutes in the jurisdictions in which we operate.

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

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 for property damage and well control with an additional limit of $450 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.

Murphy could face long-term challenges to the fossil fuels business model reducing demand and price for hydrocarbon fuels.

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 GHG emissions. The Paris Agreement and COP26 have resulted in commitments from many countries to reduce GHG emissions and have called for parties to eliminate certain fossil fuel subsidies and pursue further action on non-carbon dioxide GHGs. In addition, the federal government could issue various executive orders that may result in additional laws, rules and regulations in the area of climate change. It is possible that the Paris

Agreement, COP26, government executive orders and other such initiatives, including foreign, federal and state laws, 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. With or without renewable-energy subsidies, the unknown pace and strength of technological advancement of non-fossil-fuel energy sources creates uncertainty about the timing and pace of effects on our business model. The Company continually monitors the global climate change agenda initiatives and plans accordingly based on its assessment of such initiatives on its business.

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.

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, 2021.

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 110 to 126 and in Note D – Property, Plant and Equipment beginning on page 81.

Item 3. LEGAL PROCEEDINGS

Discussion of the Company’s legal proceedings are included in Note R – Environmental and Other Contingencies beginning on page 103.

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, 2022 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 60; President and Chief Executive Officer since 2013. Mr. Jenkins served as Chief Operating Officer from 2012 to 2013.

David R. Looney – Age 65; Executive Vice President and Chief Financial Officer since 2018.

Eric M. Hambly – Age 47; Executive Vice President, Operations since 2020. Mr. Hambly served as Executive Vice President, Onshore from 2018 to 2020 and Senior Vice President, U.S. Onshore of Murphy Exploration & Production Company from 2016 to 2018.

E. Ted Botner – Age 57; Senior Vice President, General Counsel and Corporate Secretary since 2020. Mr. Botner was Vice President, Law and Corporate Secretary from 2015 to 2020 and Manager, Law and Corporate Secretary from 2013 to 2015.

Thomas J. Mireles – Age 49; Senior Vice President, Technical Services (Health, Safety and Environment, Sustainability, Information Technology and Supply Chain) since 2018. Mr. Mireles also served as the Senior Vice President, Eastern Hemisphere of Murphy Exploration & Production Company from 2016 to 2018.

John B. Gardner – Age 53; Vice President and Treasurer since 2015. Mr. Gardner served as Treasurer from 2013 to 2015.

Christopher D. Hulse – Age 43, Vice President and Controller since 2017. Mr. Hulse was Vice President, Finance, Onshore from 2015 to 2017.

Maria A. Martinez – Age 47; Vice President, Human Resources and Administration since 2018. Ms. Martinez was Vice President, Human Resources of Murphy Exploration & Production Company from 2013 to 2018.

Louis W. Utsch – Age 56; Vice President, Tax since 2018.

Kelly L. Whitley – Age 56; Vice President, Investor Relations and Communications since 2015.

PART II

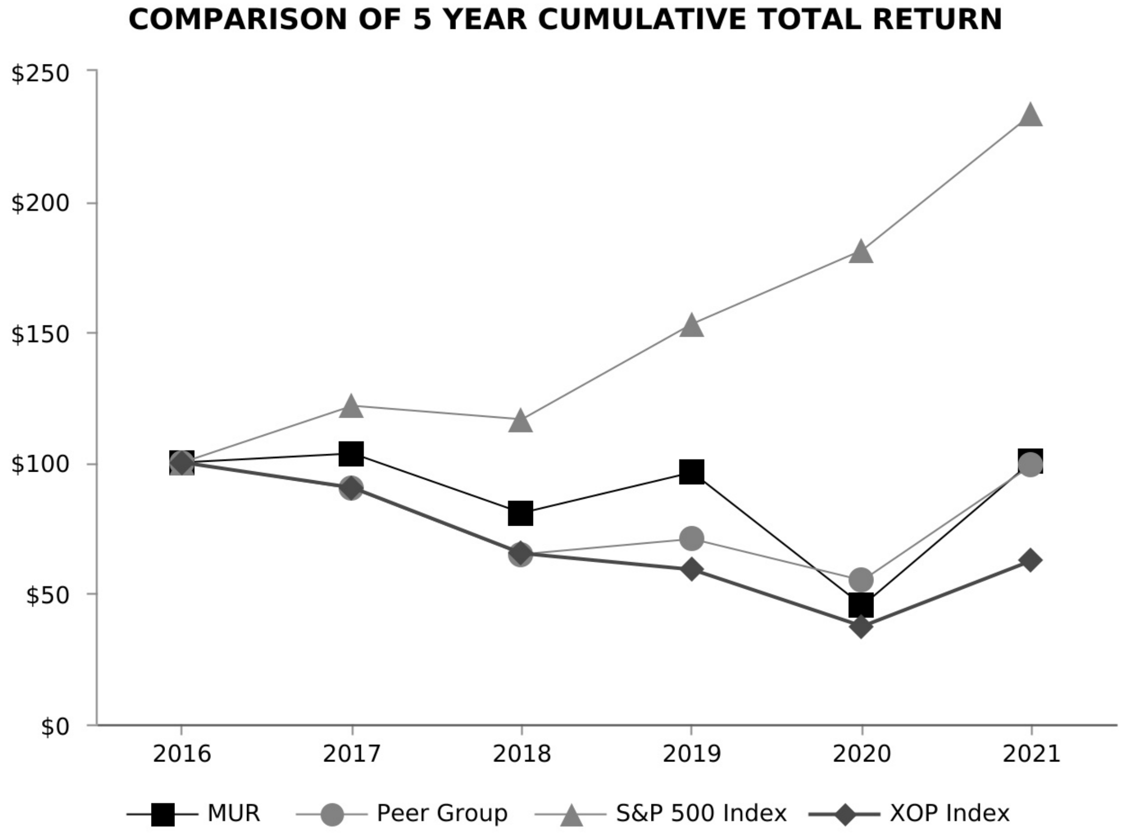
Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company's Common Stock is traded on the New York Stock Exchange using "MUR" as the trading symbol. There were 2,237 stockholders of record as of December 31, 2021. Information on dividends per share by quarter for 2021 and 2020 are reported on page 127 of this Form 10-K report.

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, 2016 in the Company, the Standard & Poor’s 500 Stock Index (S&P 500 Index), and the Company’s peer group. 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. The companies in the peer group included:

APA Corporation	Hess Corporation	PDC Energy, Inc.
Coterra Energy Inc.	Kosmos Energy Ltd.	Range Resources Corporation
CNX Resources Corporation	Marathon Oil Corporation	Southwestern Energy Company
Devon Energy Corporation	Ovintiv Inc.	Talos Energy Inc.



	2016	2017	2018	2019	2020	2021
Murphy Oil Corporation	100	103	81	96	45	101
Peer Group	100	90	65	71	55	99
S&P 500 Index	100	122	116	153	181	233
XOP Index	100	91	65	59	38	63

In 2021, the Company elected to include the S&P Oil and Gas Exploration and Production Index (XOP) in its shareholder return performance presentation as XOP reports a comprehensive view of the oil and gas exploration and production segment of the S&P Total Market Index which is more comparable for the Company than the S&P 500 Index.

Item 6. SELECTED FINANCIAL DATA

The following table contains select financial data which highlight certain trends in Murphy's results of operations and financial condition 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 Note E – Assets Held for Sale and Discontinued Operations and Note D – Property, Plant and Equipment for more information regarding the sale of Malaysia.

(Thousands of dollars except per share data)

Results of Operations for the Year	2021	2020	2019	2018	2017
Revenue from sales to customers	$ **2,801,215**	1,751,709	2,817,111	1,806,473	1,300,464
Net cash provided by continuing operations	**1,422,163**	802,708	1,489,105	749,395	613,351
Income (loss) from continuing operations	**48,753**	(1,255,294)	188,815	169,138	(553,015)
Net income (loss) attributable to Murphy	**(73,664)**	(1,148,777)	1,149,732	411,094	(311,789)
Cash dividends – diluted	**77,204**	95,989	163,669	173,044	172,565
Per Common share – diluted					
Income (loss) from continuing operations	**(0.47)**	(7.43)	0.52	0.92	(3.21)
Net income (loss) attributable to Murphy	**(0.48)**	(7.48)	6.98	2.36	(1.81)
Average common shares outstanding (thousands) – diluted	**154,291**	153,507	164,812	174,209	172,524
Cash dividends per Common share	$ **0.50**	0.625	1.00	1.00	1.00
Capital Expenditures for the Year [1]					
Continuing operations					
Exploration and production	$ **690,100**	$ 813,300	2,683,200	1,818,800	942,500
Corporate and other	**21,100**	13,300	15,000	22,700	10,300
Total capital expenditures - continuing operations	**711,200**	826,600	2,698,200	1,841,500	952,800
Discontinued operations	**—**	—	64,400	145,800	22,891
Total capital expenditures	**711,200**	826,600	2,762,600	1,987,300	975,691
Financial Condition at December 31					
Current ratio	**0.76**	1.40	1.03	1.04	1.64
Working capital (deficit)	**(283,416)**	283,971	31,538	33,756	537,396
Net property, plant and equipment	**8,127,852**	8,269,038	9,969,743	8,432,133	8,220,031
Total assets	**10,304,940**	10,620,852	11,718,504	11,052,587	9,860,942
Long-term debt [2]	**2,465,414**	2,988,067	2,803,381	3,109,318	2,906,520
Murphy shareholders' equity	**4,157,311**	4,214,337	5,467,460	4,829,299	4,620,191
Per share	**26.91**	27.44	35.75	27.91	26.77
Long-term debt – percent of capital employed [3]	**37.2**	41.5	33.9	39.2	38.6
Stockholder and Employee Data at December 31					
Common shares outstanding (thousands)	**154,463**	153,599	152,935	173,059	172,573
Number of stockholders of record	**2,237**	2,379	2,265	2,324	2,506

[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. 2021 Corporate and other Capital Expenditures includes capitalized interest costs of $16.1 million. 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 finance lease obligations (see Note G – Financing Arrangements and Debt).
[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.

In 2021, a combination of the global availability of vaccines and a relaxation of certain government-imposed lockdowns in response to the ongoing COVID-19 pandemic has led to an improving global economic outlook and subsequently increased demand for oil and gas. Several COVID-19 variants, such as Delta and Omicron, temporarily created uncertainty in the outlook; however, vaccines remained effective and therefore demand for oil and gas has remained resilient in the second half of 2021 and early 2022. The demand resilience has revealed an oil supply shortage, and hence is applying upward pressure to current and future oil and gas prices.

The OPEC+ group continues to target increasing supply by 0.4 million barrels per day (bpd) a month, with aims to fully phase out prior cuts by September 2022, at the current rate of OPEC+ supply increases. In 2020, OPEC+ cut production by 10 million bpd following the COVID-19 demand reduction. It has gradually reinstated supply so that the curtailments were approximately 5.8 million bpd at the end of 2021. However, some members of the OPEC+ are not meeting their commitments to reinstate supply.

Overall, the combination of OPEC+ supply constraints and the increase in demand driven by the global COVID-19 vaccine roll out and the relaxation of certain government-imposed lockdowns has provided upward pressure to the oil price which directly impacts the Company’s product revenue from sales compared to one year ago.

Significant Company operating and financial highlights during and at the end of 2021 were as follows:

- Produced 167 thousand barrels of oil equivalent (BOE) per day (158 thousand excluding noncontrolling interest, NCI)
- Maintained capital discipline with full year accrued capital expenditures of $711.2 million, including noncontrolling interest ($23.0 million) and King’s Quay Floating Production System (FPS) of $17.3 million (which was sold in the first quarter of 2021)
- Generated $1,422.2 million of net cash provided by operating activities and $734.0 million of adjusted cash flow [1], which includes a working capital inflow of $118.5 million
- Reduced Lease operating expense per barrel of oil equivalent by 5% year-over-year
- Preserved liquidity of $2.1 billion, including $521.2 million of cash as of December 31, 2021 and $1.6 billion available on an unsecured revolving credit facility
- Decreased full year Selling, general and administrative costs by 13% from 2020
- Repaid approximately $530 million of total debt, a 17% debt reduction in the year
- Achieved 103% total proved reserve replacement with year-end proved reserves of 716.9 million barrels of oil equivalent

Throughout this section, the term, ‘excluding noncontrolling interest’ or ‘excluding NCI’ refers to amounts attributable to Murphy. Unless noted, amounts include noncontrolling interest.

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 and expenses related to exploration, administration, and for capital borrowed from lending institutions and note holders.

[1] Adjusted cash flow is calculated as cash flow from operations less capital expenditures ($688.2 million).

Changes in the price of crude oil and natural gas have a significant impact on the profitability of the Company. In 2021, liquids from continuing operations represented 62% of total hydrocarbons produced on an energy equivalent basis. In 2022, the Company's ratio of hydrocarbon production represented by liquids is expected to be 59%. If the prices for crude oil and natural gas are lower in 2022 or beyond, this will have an unfavorable impact on the Company's operating profits; likewise, if prices are higher, this will have a favorable impact. 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 recovered in 2021 compared to the 2020 period and were higher compared to 2019. The sales price of a barrel of West Texas Intermediate (WTI) crude oil averaged $67.91 in 2021, $39.40 in 2020, and $57.03 in 2019. In 2022, the WTI price has thus far been above those in the comparable period in 2021.

The WTI index increased 72% over the prior year principally as a result of OPEC+ supply constraints and the increase in demand driven by the global COVID-19 vaccine roll out as discussed above.

The most common crude oil indices used to price the Company's crude include WTI Houston (MEH), Heavy Louisiana Sweet (HLS), Mars and Brent.

The NYMEX natural gas price per million British Thermal Units (MMBTU) averaged $3.84 in 2021, $1.99 in 2020 and $2.52 in 2019. The 2021 NYMEX natural gas price was higher compared to the 2020 price and natural gas prices in North America in 2022 have thus far been above those in the comparable period in 2021.

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)	**2021**	2020	2019
Income (loss) from continuing operations before income taxes	**$ 42.9**	(1,549.0)	203.5
Net (loss) income attributable to Murphy	**(73.7)**	(1,148.8)	1,149.7
Diluted EPS	**(0.48)**	(7.48)	6.98
(Loss) income from continuing operations attributable to Murphy	**(72.4)**	(1,141.6)	85.2
Diluted EPS	**(0.47)**	(7.43)	0.52
(Loss) income from discontinued operations	**(1.2)**	(7.2)	1,064.5
Diluted EPS	**(0.01)**	(0.05)	6.46

For the year ended December 31, 2021, the Company produced 167 thousand barrels of oil equivalent per day (including noncontrolling interest) from continuing operations. The Company invested $711.2 million in capital expenditures (on a value of work done basis) for the year ended December 31, 2021, which included $23.0 million attributable to noncontrolling interest and $17.3 million to fund the development of the King's Quay FPS (which was subsequently sold). The Company reported net income from continuing operations of $48.8 million (which included post tax impairment charges of $151.5 million and income attributable to noncontrolling interest of $121.2 million) for the year ended December 31, 2021.

For the year ended December 31, 2020, the Company produced 175 thousand barrels of oil equivalent per day (including noncontrolling interest) from continuing operations. The Company invested $826.6 million in capital expenditures (on a value of work done basis) for the year ended December 31, 2020, which included $21.7 million attributable to noncontrolling interest and $92.8 million to fund the development of the King's Quay FPS. The Company reported net loss from continuing operations of $1,255.3 million (which included post tax impairment charges of $854.2 million and loss attributable to noncontrolling interest of $113.7 million) for the year ended December 31, 2020.

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 Adjusted 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.

	Year Ended December 31,		
(Millions of dollars, except per barrel of oil equivalents sold)	**2021**	2020	2019
Net (loss) income attributable to Murphy (GAAP)	**$ (73.7)**	(1,148.8)	1,149.7
Income tax expense (benefit)	**(5.9)**	(293.7)	14.7
Interest expense, net	**221.8**	169.4	219.3
Depreciation, depletion and amortization expense [1]	**760.6**	932.6	1,076.5
EBITDA attributable to Murphy (Non-GAAP)	**902.8**	(340.5)	2,460.2
Impairment of assets [1]	**196.3**	1,072.5	—
Mark-to-market loss (gain) on crude oil derivative contracts	**112.1**	69.3	33.4
Asset retirement obligation (gains) losses	**(71.8)**	(2.8)	—
Mark-to-market loss (gain) on contingent consideration	**63.2**	(13.8)	8.7
Accretion of asset retirement obligations [1]	**41.1**	42.1	40.5
Unutilized rig charges	**8.7**	16.0	—
Discontinued operations loss (income)	**1.2**	7.2	(1,064.5)
Foreign exchange losses (gains)	**(1.0)**	0.7	6.4
Restructuring expenses	**—**	50.0	—
Inventory loss	**—**	8.3	—
Seal insurance proceeds	**—**	(1.7)	(8.0)
Business development transaction costs	**—**	—	24.4
Write-off of previously suspended exploration wells	**—**	—	13.2
Adjusted EBITDA attributable to Murphy (Non-GAAP)	**$ 1,252.6**	907.3	1,514.3
Total barrels of oil equivalents sold from continuing operations attributable to Murphy (thousands of barrels)	**57,476**	60,189	63,128
Adjusted EBITDA per barrel of oil equivalents sold	**$ 21.79**	15.07	23.99

[1] Depreciation, depletion, and amortization expense, impairment of assets and accretion of asset retirement obligations used in the computation of adjusted EBITDA exclude 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, 2021, 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 (loss) income is presented in the following table.

(Millions of dollars)	**2021**	2020	2019
Exploration and production – continuing operations			
United States	$ **766.3**	(1,014.3)	518.4
Canada	**(16.1)**	(35.0)	(4.3)
Other International	**(33.5)**	(85.6)	(53.5)
Total exploration and production – continuing operations	**716.7**	(1,134.9)	460.6
Corporate and other	**(668.0)**	(120.3)	(271.8)
Income (loss) from continuing operations	**48.7**	(1,255.2)	188.8
(Loss) income from discontinued operations	**(1.2)**	(7.2)	1,064.5
Net income (loss) including noncontrolling interest	**47.5**	(1,262.4)	1,253.3
Net income (loss) attributable to noncontrolling interest	**121.2**	(113.7)	103.6
Net (loss) income attributable to Murphy	$ **(73.7)**	(1,148.7)	1,149.7

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

(Millions of dollars)		**2021**	2020	2019
United States	Oil and natural gas liquids	$ **2,199.7**	1,335.8	2,285.8
	Natural gas	**121.7**	69.4	73.9
Canada	Oil and natural gas liquids	**228.9**	174.0	287.4
	Natural gas	**245.9**	170.6	158.4
Other	Oil	**4.9**	1.8	11.6
Total oil and natural gas revenues		$ **2,801.1**	1,751.6	2,817.1

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.

2021 vs 2020

All amounts include amounts attributable to a noncontrolling interest in MP GOM (a subsidiary of Murphy Expro USA, operating and developing properties in the Gulf of Mexico) and exclude discontinued operations, unless otherwise noted.

Exploration and production (E&P) from continuing operations recorded earnings of $716.7 million in 2021 compared to a loss of $1,134.9 million in 2020. Results were favorable $1,851.6 million in 2021 compared to 2020 primarily due to higher oil, natural gas liquid and natural gas prices, lower impairment charges, lower depreciation, depletion and amortization (DD&A), lower lease operating expenses (LOE), lower exploration expenses and lower general and administrative (G&A) expenses, partially offset by higher transportation, gathering and processing and income tax charges. See below for further details.

Crude oil price realizations averaged $66.80 per barrel in the current year compared to $38.02 per barrel in 2020, a price increase of 76% year over year. U.S. natural gas realized price per thousand cubic feet (MCF) averaged $3.71 in the current year compared to $2.02 per MCF in 2020, a price increase of 84% year over year. Canada natural gas realized price per MCF averaged U.S. $2.43 in the current year compared to U.S. $1.79 per MCF in 2020, a price increase of 36% year over year. Oil and natural gas production costs, including associated production taxes, on a per-unit basis, were $9.53 in 2021 excluding transportation, gathering and processing (TGP) (2020: $9.81). The favorable decrease in per-unit production costs in 2021 was primarily attributable to reduced costs associated with well workovers and concerted efficiency efforts.

United States E&P operations reported earnings of $766.3 million in 2021 compared to a loss of $1,014.3 million in 2020. Results were favorable $1,780.6 million in 2021 compared to the 2020 period primarily due to no impairment charges in 2021 (2020*:* $1,152.5 million), higher total revenues ($925.7 million), lower DD&A ($132.9 million), and lower LOE ($70.5 million), partially offset by higher income tax expense ($428.1 million) and higher other operating expense ($77.9 million). The impairment charge in the prior year was primarily the result of lower forecast future prices as of March 31, 2020, as a result of lower oil demand (COVID-19 impact) and abundant oil supply at the time of the assessment.

Higher revenues were primarily due to higher realized prices (oil and condensate, natural gas and NGLs) year over year, partially offset by lower sales volume (7,514 barrels of oil equivalent per day lower) as a result of lower capital expenditures in 2020. Lower DD&A is a result of the prior year impairment charge reducing the depreciable asset base. Lower lease operating expenses were primarily due to higher GOM workover costs in the prior year at Cascade ($51.3 million) and Dalmatian ($20.5 million). Higher income tax expense is a result of higher pre-tax income principally due to higher oil price and lower DD&A and LOE. Higher other operating expense is primarily due to an unfavorable mark-to-market revaluation on contingent consideration ($63.2 million; as a result of higher commodity prices) from prior GOM acquisitions.

Canadian E&P operations reported a loss of $16.1 million in 2021 compared to a loss of $35.0 million in 2020. Results were favorable $18.9 million compared to 2020 primarily due to higher revenue ($130.5 million) and lower DD&A ($49.4 million), partially offset by an impairment charge ($171.3 million), higher lease operating expense ($14.7 million), transportation, gathering and processing ($15.8 million) and income tax charges ($19.7 million). 2021 results include an impairment charge ($171.3 million) recorded in the first quarter following notice from the operator of asset abandonment at Terra Nova at the time of the assessment and a partially offsetting credit of $71.8 million as of September 30, 2021 reported in 'other operating expense' as a result of the deferral of an asset retirement obligation at Terra Nova following the sanction of an asset life extension project and reversal of the asset abandonment decision.

Higher revenue is primarily attributable to higher natural gas prices and volumes at Tupper Montney and higher oil prices at Hibernia and Kaybob Duvernay. Lower DD&A is primarily due to lower production volumes at Kaybob Duvernay following reduced capital expenditures throughout 2020. Higher lease operating expenses and transportation, gathering and processing costs are due to higher gas processing and downstream transportation capacity, which are expected to be utilized by growth at Tupper Montney in the future.

Other international E&P operations reported a loss from continuing operations of $33.5 million in 2021 compared to a loss of $85.6 million in 2020. Results were favorable $52.1 million in 2021 compared to 2020 primarily due to lower impairment charges ($21.7 million), lower income tax charges ($11.6 million), lower exploration expenses ($5.9 million) primarily in Brazil and Mexico and lower LOE ($4.8 million).

2020 vs 2019

All amounts include amounts attributable to a noncontrolling interest in MP GOM (a subsidiary of Murphy Expro USA, operating and developing properties in the Gulf of Mexico) and exclude discontinued operations, unless otherwise noted.

E&P from continuing operations recorded a loss of $1,134.9 million in 2020 compared to earnings of $460.6 million in 2019. The results for 2020 were unfavorably impacted by impairment charges and lower oil and natural gas liquid prices and volumes, partially offset by lower depreciation and accretion expenses, G&A expenses, exploration expenses and taxes.

As a result of the COVID-19 pandemic and certain major global suppliers announcing crude oil supply increases in the first quarter of 2020, commodity prices were generally lower in 2020 vs 2019. Crude oil price realizations averaged $38.02 per barrel in 2020 compared to $60.27 per barrel in 2019, a price decrease of 37% year over year. U.S. natural gas realized price per MCF averaged $2.02 in 2020 compared to $2.45 per MCF in 2019, a price decrease of 18% year over year. Canada natural gas realized price per MCF averaged U.S. $1.79 in 2020 compared to U.S. $1.60 per MCF in 2019, a price increase of 12% year over year. Oil and natural gas production costs, including associated production taxes, on a per-unit basis, were $9.81 in 2020 excluding TGP (2019: $9.66). The increase in production costs in 2020 was primarily attributable to costs associated with well workovers at Cascade and Dalmatian in the U.S. Gulf of Mexico.

United States E&P operations reported a loss of $1,014.3 million in 2020 compared to earnings of $518.4 million in 2019. Results were $1,532.7 million unfavorable in 2020 compared to the 2019 period primarily due to higher impairment charges ($1,152.5 million), lower revenues ($955.2 million) and higher lease operating expenses ($15.4 million), partially offset by lower income tax expense ($359.8 million), depreciation, depletion and amortization (DD&A) ($129.3 million), G&A ($49.7 million), other operating expenses ($27.2 million) and transportation, gathering, and processing ($13.1 million). The impairment charge was primarily the result of lower future prices at the time of calculation, as a result of decreased oil demand.

Lower revenues were primarily due to lower commodity prices year over year and lower volumes in the U.S. Gulf of Mexico (as a result of shut-ins related to hurricanes and storms and lower capital expenditures). Higher lease operating expenses were due primarily to Gulf of Mexico well workovers at Cascade ($51.3 million) and Dalmatian ($20.5 million). Lower income tax expense was a result of pre-tax losses driven by the impairment charge and lower commodity prices. Lower other operating expense was primarily due to a favorable mark-to-market revaluation on contingent consideration (as a result of lower commodity prices) from prior Gulf of Mexico (GOM) acquisitions ($13.8 million). Lower G&A was due to cost reductions and lower headcount as a result of restructuring (primarily closing the El Dorado and Calgary offices).

Canadian E&P operations reported a loss of $35.0 million in 2020 compared to income of $4.3 million in 2019. Results were unfavorable $30.7 million compared to 2019 primarily due to lower revenue ($101.2 million) partially offset by lower DD&A ($29.8 million), lease operating expense ($20.8 million), income tax charges ($18.5 million) and G&A ($12.9 million). Lower revenues were due to lower oil and condensate prices versus the prior year and a shut-in at Terra Nova for Asset Integrity work (starting in December 2019 and expected to continue until 2022). Lower DD&A and lease operating expenses were a result of lower sales. Lower income tax expense was a result of pre-tax losses. Lower G&A was due to cost reductions and lower headcount as a result of restructuring.

Other international E&P operations reported a loss from continuing operations of $85.6 million in 2020 compared to a loss of $53.5 million in the prior year. The 2020 results included an impairment charge of $39.7 million and lower revenues of $9.8 million in Brunei.

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

(Dollars per equivalent barrel)	**2021**	2020	2019
Continuing operations			
United States – Eagle Ford Shale			
Lease operating expense	**$ 8.96**	9.08	8.70
Severance and ad valorem taxes	**2.91**	2.06	2.82
Depreciation, depletion and amortization (DD&A) expense	**27.59**	26.22	24.19
United States – Gulf of Mexico			
Lease operating expense	**10.63**	11.95	10.89
Severance and ad valorem taxes	**0.07**	—	—
DD&A expense	**9.51**	13.48	16.43
Canada – Onshore			
Lease operating expense	**6.20**	4.63	5.49
Severance and ad valorem taxes	**0.09**	0.07	0.07
DD&A expense	**7.64**	9.93	10.94
Canada – Offshore			
Lease operating expense	**13.04**	17.86	14.95
DD&A expense	**12.80**	12.01	13.07
Total oil and natural gas continuing operations			
Lease operating expense	**8.86**	9.34	8.95
Severance and ad valorem taxes	**0.68**	0.44	0.71
DD&A expense	**13.05**	15.36	16.98
Total oil and natural gas continuing operations – excluding noncontrolling interest			
Lease operating expense	**8.65**	9.10	8.81
Severance and ad valorem taxes	**0.71**	0.47	0.76
DD&A expense	**13.23**	15.49	17.05
Discontinued Operations			
Malaysia			
Lease operating expense	**—**	—	16.49
DD&A expense	**—**	—	4.60

Corporate

2021 vs 2020

Corporate activities, which include interest expense and income, foreign exchange effects, realized and unrealized gains and losses on derivative instruments (forward swaps and collars to hedge the price of oil sold) and corporate overhead not allocated to Exploration and Production, reported a loss of $668.0 million in 2021 compared to a loss of $120.3 million in 2020. The $547.7 million unfavorable variance is principally due to higher net losses on derivative instruments in 2021 compared to the 2020 period (2021: $525.9 million loss; 2020: $202.7 million gain) and higher interest expense ($53.0 million), partially offset by a higher tax benefit ($148.3 million), lower restructuring charges ($48.8 million), lower G&A expenses ($12.9 million), and lower impairment charges ($7.1 million). Realized and unrealized losses on derivative instruments are due to an increase in market pricing in future periods whereby the swap contracts provide the Company with a fixed price and the collar contracts provide for a minimum (floor) and a maximum (ceiling) price, with variability in between the floor and ceiling. Higher interest costs are principally due to debt redemption costs on the 2022 notes and $550.0 million issuance of new notes in March 2021 that bear interest at a rate of 6.375% and mature on July 15, 2028. Higher income tax benefit is a result of higher pre-tax loss driven by the higher realized and unrealized losses on derivative instruments. Lower restructuring charges and G&A are due to the 2020 cost reduction efforts which included closing the Company’s previous headquarters office in El Dorado, Arkansas, its office in Calgary, Alberta, and consolidating all worldwide staff activities to its existing office location in Houston, Texas.

2020 vs 2019

In 2020, the Company announced that it was closing its headquarters office in El Dorado, Arkansas, its office in Calgary, Alberta, and consolidating all worldwide staff activities to its existing office location in Houston, Texas. As a result, certain directly attributable costs and charges were recognized and reported as Restructuring charges as part of net loss in 2020. These costs included severance, relocation, IT costs, pension curtailment and a write-off of the right of use asset lease associated with the Canada office. Further, the office building in El Dorado was classified as held for sale.

Corporate activities, which include interest expense and income, foreign exchange effects, realized and unrealized gains and losses on derivative instruments and corporate overhead not allocated to Exploration and Production, reported a loss of $120.3 million in 2020 compared to a loss of $271.8 million in 2019. The $151.5 million favorable variance was primarily due to higher realized gains on forward swap commodity contracts ($239.5 million), lower interest charges ($50.2 million), lower G&A ($14.5 million), and partially offset by higher tax charges ($55.3 million), restructuring charges ($48.8 million) related to the closure of the El Dorado and Calgary offices, and impairment charges ($14.1 million). Higher realized gains on forward swap commodity contracts were due to lower market pricing whereby the contract provides the Company with a fixed price. Interest charges were lower primarily due to 2019 temporary borrowings on the Company’s revolving credit facility (RCF) to fund the LLOG acquisition (the RCF borrowings were repaid in the third quarter 2019 following the divestment of the Malaysia business) and gains from the buy-back of debt in the second quarter 2020. As of December 31, 2020, the average forward NYMEX WTI prices for 2021 and 2022 were $48.34 and $46.76, respectively (versus fixed hedge prices of $42.77 and $44.88).

Production Volumes and Prices

2021 vs 2020

Total hydrocarbon production from all E&P continuing operations averaged 167,356 barrels of oil equivalent per day in 2021, which represented a 4% decrease from the 174,636 barrels per day produced in 2020.

Average crude oil and condensate production from continuing operations was 95,705 barrels per day in 2021 compared to 103,966 barrels per day in 2020. The decrease of 8,261 barrels per day was principally due to lower volumes in the Gulf of Mexico (2,703 barrels per day primarily due to reservoir decline), lower volumes at Kaybob Duvernay (2,272 barrels per day due to well decline) and lower Eagle Ford Shale production (765 barrels per day). On a worldwide basis, the Company’s crude oil and condensate prices averaged $66.80 per barrel in 2021 compared to $38.02 per barrel in the 2020 period, an increase of 76% year over year.

Total production of natural gas liquids (NGL) from continuing operations was 10,385 barrels per day in 2021 compared to 11,541 barrels per day in the 2020 period. The average sales price for U.S. NGL was $27.97 per barrel in 2021 compared to $11.29 per barrel in 2020. The average sales price for NGL in Canada was $40.18 per barrel in 2021 compared to $18.54 per barrel in 2020. NGL prices are higher in Canada due to the higher value of product produced at the Kaybob and Placid assets.

Natural gas sales volumes from continuing operations averaged 368 million cubic feet per day (MMCFD) in 2021 compared to 355 MMCFD in 2020. The increase of 13 MMCFD was primarily the result of higher volumes in Canada. Higher natural gas volumes in Canada are primarily due to bringing online 14 new wells at Tupper Montney in 2021. Higher volumes at Tupper Montney were partially offset by lower gas volumes in the Gulf of Mexico.

Natural gas prices for the total Company averaged $2.74 per thousand cubic feet (MCF) in 2021, versus $1.85 per MCF average in the same period of 2020. Average realized natural gas prices in the US and Canada in 2021 were $3.71 and $2.43 per MCF, respectively.

2020 vs 2019

Total hydrocarbon production from continuing operations averaged 174,636 barrels of oil equivalent per day in 2020, which represented a 6% decrease from the 185,649 barrels per day produced in 2019. Production in the Gulf of Mexico was significantly impacted by a record breaking hurricane year which resulted in shut-ins and loss of approximately 6.4 MBOED of production in 2020. Lower volumes in the Eagle Ford Shale volumes were due to lower capital expenditures.

Average crude oil and condensate production from continuing operations was 103,966 barrels per day in 2020 compared to 114,742 barrels per day in 2019. The decrease of 10,776 barrels per day was principally due to lower Eagle Ford Shale production (8,158 barrels per day) and lower volumes in the Gulf of Mexico (2,143 barrels per day) as stated above. On a worldwide basis, the Company’s crude oil and condensate prices averaged $38.02 per barrel in 2020 compared to $60.27 per barrel in 2019, a decrease of 37% year over year, resulting from the global downturn triggered by the COVID-19 pandemic.

Total production of natural gas liquids (NGL) from continuing operations was 11,541 barrels per day in 2020 compared to 11,888 per day in 2019. The average sales price for U.S. NGL was $11.29 per barrel in 2020 compared to $14.85 per barrel in 2019. The average sales price of NGL in Canada was $18.54 per barrel in 2020 compared to $26.04 per barrel in 2019. 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 355 million cubic feet per day (MMCFD) in 2020 compared to 354 MMCFD in 2019. The increase of 1 MMCFD was a primarily the result of higher volumes in the Gulf of Mexico (14 MMCFD) due to a full year contribution from the assets associated with the LLOG transaction.

Natural gas prices for the total Company averaged $1.85 per thousand cubic feet (MCF) in 2020, versus $1.8 per MCF average in 2019. Average prices in the U.S. and Canada in 2020 were $2.02 and $1.79 respectively.

The following table contains hydrocarbons produced during the three years ended December 31, 2021.

Barrels per day unless otherwise noted		2021	2020	2019
Continuing operations				
Net crude oil and condensate				
United States	Onshore	**25,655**	26,420	34,578
	Gulf of Mexico [1]	**60,717**	64,680	66,823
Canada	Onshore	**5,312**	7,888	6,329
	Offshore	**3,765**	4,893	6,543
Other		**256**	85	469
Total net crude oil and condensate - continuing operations		**95,705**	103,966	114,742
Net natural gas liquids				
United States	Onshore	**5,092**	5,248	5,731
	Gulf of Mexico [1]	**4,176**	4,978	4,894
Canada	Onshore	**1,117**	1,315	1,263
Total net natural gas liquids - continuing operations		**10,385**	11,541	11,888
Net natural gas – thousands of cubic feet per day				
United States	Onshore	**28,565**	27,985	30,692
	Gulf of Mexico [1]	**61,240**	66,105	52,068
Canada	Onshore	**277,790**	260,683	271,355
Total net natural gas - continuing operations		**367,595**	354,773	354,115
Total net hydrocarbons - continuing operations including NCI [2,3]		**167,356**	174,636	185,649
Noncontrolling interest				
Net crude oil and condensate – barrels per day		**(8,623)**	(9,962)	(11,226)
Net natural gas liquids – barrels per day		**(303)**	(416)	(507)
Net natural gas – thousands of cubic feet per day [2]		**(3,236)**	(3,843)	(3,965)
Total noncontrolling interest		**(9,465)**	(11,019)	(12,394)
Total net hydrocarbons - continuing operations excluding NCI [2,3]		**157,891**	163,617	173,255
Discontinued operations				
Net crude oil and condensate – barrels per day		**—**	—	12,215
Net natural gas liquids – barrels per day		**—**	—	325
Net natural gas – thousands of cubic feet per day [2]		**—**	—	50,758
Total discontinued operations		**—**	—	21,000
Total net hydrocarbons produced excluding NCI [2,3]		**157,891**	163,617	194,255
Estimated net hydrocarbon reserves - million equivalent barrels [3,4]		**716.9**	714.9	825.0

[1] Includes 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] December 31, 2021, 2020 and 2019, include 18.4 MMBOE, 17.4 MMBOE and 24.6 MMBOE, respectively, relating to noncontrolling interest.

The following table contains hydrocarbons sold during the three years ended December 31, 2021.

Barrels per day unless otherwise noted		2021	2020	2019
Continuing operations				
Net crude oil and condensate				
United States	Onshore	**25,655**	26,420	34,578
	Gulf of Mexico [1]	**60,544**	65,621	66,272
Canada	Onshore	**5,312**	7,888	6,329
	Offshore	**3,559**	4,958	6,722
Other		**195**	78	427
Total net crude oil and condensate - continuing operations		**95,265**	104,965	114,328
Net natural gas liquids				
United States	Onshore	**5,092**	5,248	5,731
	Gulf of Mexico [1]	**4,176**	4,978	4,894
Canada	Onshore	**1,117**	1,315	1,263
Total net natural gas liquids - continuing operations		**10,385**	11,541	11,888
Net natural gas – thousands of cubic feet per day				
United States	Onshore	**28,565**	27,985	30,692
	Gulf of Mexico [1]	**61,240**	66,105	52,068
Canada	Onshore	**277,790**	260,683	271,355
Total net natural gas - continuing operations		**367,595**	354,773	354,115
Total net hydrocarbons - continuing operations including NCI [2,3]		**166,916**	175,635	185,235
Noncontrolling interest				
Net crude oil and condensate – barrels per day		**(8,605)**	(10,127)	(11,115)
Net natural gas liquids – barrels per day		**(303)**	(416)	(507)
Net natural gas – thousands of cubic feet per day [2]		**(3,236)**	(3,843)	(3,965)
Total noncontrolling interest		**(9,447)**	(11,184)	(12,283)
Total net hydrocarbons - continuing operations excluding NCI [2,3]		**157,469**	164,451	172,952
Discontinued operations				
Net crude oil and condensate – barrels per day		**—**	—	12,100
Net natural gas liquids – barrels per day		**—**	—	296
Net natural gas – thousands of cubic feet per day [2]		**—**	—	50,758
Total discontinued operations		**—**	—	20,856
Total net hydrocarbons sold excluding NCI [2,3]		**157,469**	164,451	193,808

[1] Includes 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.

The following table contains the weighted average sales prices excluding transportation cost deduction for the three years ended December 31, 2021. Comparative periods are conformed to current presentation.

		2021	2020	2019
Weighted average Exploration and Production sales prices				
Continuing operations				
Crude oil and condensate – dollars per barrel				
United States	Onshore	$ **66.90**	36.54	59.45
	Gulf of Mexico [1]	**66.93**	39.15	61.09
Canada [2]	Onshore	**61.79**	32.42	50.29
	Offshore	**71.39**	39.40	64.91
Other		**69.21**	63.51	74.70
Natural gas liquids – dollars per barrel				
United States	Onshore	**26.97**	11.67	14.60
	Gulf of Mexico [1]	**29.14**	10.84	15.10
Canada [2]	Onshore	**40.18**	18.54	26.04
Natural gas – dollars per thousand cubic feet				
United States	Onshore	**3.83**	1.95	2.47
	Gulf of Mexico [1]	**3.67**	2.04	2.43
Canada [2]	Onshore	**2.43**	1.79	1.60
Discontinued operations				
Crude oil and condensate – dollars per barrel				
Malaysia [3]	Sarawak	**—**	—	70.39
	Block K	**—**	—	65.75
Natural gas liquids – dollars per barrel				
Malaysia [3]	Sarawak	**—**	—	48.23
Natural gas – dollars per thousand cubic feet				
Malaysia [3]	Sarawak	**—**	—	3.60
	Block K	**—**	—	0.24

[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.

Financial Condition

Cash Provided by Operating Activities

Net cash provided by continuing operating activities was $1,422.2 million in 2021 compared to $802.7 million in 2020. The increased cash provided by continuing operating activities of $619.5 million is primarily attributable to higher revenue from sales to customers ($1,049.5 million), positive effect of movements on payable and receivable working capital balances ($118.5 million), lower lease operating expenses ($60.5 million), lower general and administrative and cash restructuring expenses ($50.7 million), partially offset by higher cash payments made on forward swap commodity contracts (2021: realized loss of $413.7 million; 2020: realized gain of $272.0 million). Higher revenues were primarily due to higher commodity prices driven by OPEC+ supply constraints and the increase in demand.

Cash flow provided by continuing operations was $686.4 million lower in 2020 than in 2019 primarily due to lower revenues, partially offset by higher cash payments received on forward swap commodity contracts. Lower revenues were primarily due to lower commodity prices resulting from lower demand triggered by the COVID-19 pandemic and lower volumes (due to reduced capital expenditures).

The total reductions of operating cash flows for interest paid (which excludes debt redemption costs reported in Financing activities) during the three years ended December 31, 2021, 2020, and 2019 were $165.7 million, $191.6 million, and $179.7 million, respectively. Lower cash interest paid in 2021 was due to the repayment of the $200 million outstanding on the revolving credit facility, the early redemption of the 2022 notes and the early redemption of $300 million of the 2024 notes, partially offset by interest paid on the issuance of 2028 notes in the first quarter of 2021. Higher cash interest paid in 2020 was due to the new 2027 notes paying interest at 5.875% and revolver borrowing during the year.

Cash Used for Investing Activities

Cash used for property additions and dry holes, which includes amounts expensed, were $688.2 million and $872.8 million in 2021 and 2020, respectively. These amounts include $17.7 million and $113.0 million used to fund the development of the King’s Quay FPS in 2021 and 2020. In March 2021, the King’s Quay FPS was sold to ArcLight Capital Partners, LLC (ArcLight) for proceeds of $267.7 million, which reimbursed the Company for previously incurred capital expenditures. 2021 also includes proved property acquisitions for an additional interest in the Lucius property of $19.9 million. Lower property additions in 2021 are principally due to lower capital spending at Eagle Ford Shale and lower spend on King’s Quay.

In 2019, property additions included $1,261.1 million for the LLOG acquisition.

The accrual (value of work done) basis of capital expenditures were as follows:

	Year Ended December 31,		
(Millions of dollars)	**2021**	2020	2019
Capital Expenditures			
Exploration and production	**$ 690.1**	813.3	2,683.2
Corporate	**21.1**	13.3	15.0
Total capital expenditures	**$ 711.2**	826.6	2,698.2
Total capital expenditures excluding proved property acquisitions	**$ 711.2**	826.6	1,437.1
Total capital expenditures excluding proved property acquisitions and NCI	**$ 688.2**	804.9	1,402.3

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

(Millions of dollars)	Year Ended December 31, 2021	2020	2019
Property additions and dry hole costs per cash flow statements	$ **670.5**	759.8	1,244.1
Property additions King's Quay per cash flow statements	**17.7**	113.0	100.2
Geophysical and other exploration expenses	**26.9**	32.3	48.5
Capital expenditure accrual changes and other	**(3.9)**	(78.5)	93.1
Acquisition of oil properties per the cash flow statements	**—**	—	1,212.3
Total capital expenditures	$ **711.2**	826.6	2,698.2

Capital expenditures in the exploration and production business in 2021 compared to 2020 have decreased as a result of capital expenditure reductions to support generating free cash flow.

Cash Used by and Provided by Financing Activities

Net cash required by financing activities was $794.5 million in 2021 compared to net cash provided by financing activities of $39.7 million during 2020. In 2021, the cash required by financing activities was principally due to the repayment of the balance outstanding on the revolving credit facility ($200.0 million), the early redemption of the remainder of the 2022 notes ($576.4 million), the early redemption of a portion of the 2024 notes ($300.0 million), costs associated with early redemption ($39.3 million), dividends paid ($77.2 million) and distributions to noncontrolling interest ($137.5 million), partially offset by issuance of 2028 notes ($541.9 million).

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. As of December 31, 2021, the Company has a $1.6 billion senior unsecured guaranteed credit facility (RCF) with a major banking consortium, which expires in November 2023. As of December 31, 2021 and in the event it is required to fund investing activities from borrowings, the Company has approximately $1.6 billion available on its committed revolving credit facility.

In 2020, net cash provided by financing activities of $39.7 million was principally from borrowings on the Company's RCF ($200.0 million), partially offset by dividends paid ($96.0 million) and distributions to noncontrolling interest ($43.7 million).

In 2019, net cash required by financing activities of $1,130.0 million consisted of $548.0 million to redeem a portion of the 2022 notes, $499.9 million to buy back issued ordinary shares, $325.0 million to repay the RCF, $163.7 million to pay dividends, and $128.2 million to cover distributions to noncontrolling interest, net of proceeds of $542.4 million from the issuance of the 2027 notes.

Working Capital

At the end of 2021, working capital (total current assets less total current liabilities, excluding assets and liabilities held for sale) amounted to a net working capital liability of $298.9 million (2020: net working capital liability of $29.4 million). The total working capital liability increase of $269.5 million in 2021 is primarily attributable to higher accounts payable ($216.0 million) and higher other accrued liabilities ($210.3 million), partially offset by higher cash and cash equivalents ($210.6 million). The higher accounts payable is due to the increase in unrealized losses on derivative instruments (commodity swap and collar) maturing in the next 12 months. The higher other accrued liabilities are principally due to higher liabilities associated with current asset retirement obligations, and contingent consideration liabilities related to prior GOM acquisitions.

Cash and cash equivalents as of December 31, 2021 totaled $521.2 million (2020: $310.6 million). There were no borrowings from the RCF outstanding at the end of the year (2020: $200.0 million). Cash in the year benefited from a positive working capital inflow of $118.5 million principally due to increasing liabilities associated with a major U.S. Offshore capital project expected to begin production mid-2022.

Cash and invested cash are maintained in several operating locations outside the U.S. As of December 31, 2021, Cash and cash equivalents held outside the U.S. included U.S dollar equivalents of approximately $242.9 million (2020: $119.3 million), the majority of which was held in Canada ($175.0 million). In addition, approximately $26.2 million and $14.0 million of cash was held in Brazil and the U.K., respectively. 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 I – Income Taxes for further information regarding potential tax expense that could be incurred upon distribution of foreign earnings back to the United States.

Capital Employed

As of December 31, 2021, long-term debt of $2,465.4 million had decreased by $522.7 million compared to December 31, 2020, as a result the net repayment of the $200.0 million outstanding on the revolving credit facility December 31, 2020, the early redemption of the 2022 notes and the early redemption of $300.0 million of the 2024 notes, partially offset by issuance of 2028 notes. The fixed-rate notes had a weighted average maturity of 7.5 years and a weighted average coupon of 6.2%.

A summary of capital employed as of December 31, 2021 and 2020 follows.

	December 31, 2021		December 31, 2020	
(Millions of dollars)	**Amount**	**%**	Amount	%
Capital employed				
Long-term debt	**$ 2,465.4**	**37.2 %**	$ 2,988.1	41.5 %
Murphy shareholders' equity	**4,157.3**	**62.8 %**	4,214.3	58.5 %
Total capital employed	**$ 6,622.7**	**100.0 %**	$ 7,202.4	100.0 %

Murphy shareholders’ equity was $4.16 billion at the end of 2021 (2020: $4.21 billion). Shareholders’ equity decreased in 2021 primarily due to dividends paid ($77.2 million) and a 2021 net loss ($73.7 million), partially offset by a favorable revaluation of pension assets and liabilities ($59.8 million). A summary of transactions in stockholders’ equity accounts is presented in the Consolidated Statements of Stockholders’ Equity on page 72 of this Form 10-K report.

Other Balance Sheet Activity - Long-Term Assets and Liabilities

Other significant changes in Murphy’s balance sheet at the end of 2021, compared to 2020 are discussed below.

Property, plant and equipment, net of depreciation decreased $141.2 million principally due to an annual charge of depreciation, depletion and amortization ($795.1 million) of these balances and impairment charges ($196.3 million), offset by capital expenditures in the year. Capital expenditures are discussed above in the ‘Cash Used for Investing Activities’ section. An impairment charge of $171.3 million was triggered when the operator at Terra Nova provided notice of abandonment in the first quarter of 2021, before a commercial resolution in the third quarter of 2021 led Murphy to acquire an additional 7.525% in a commercial settlement with the other partners. The commercial resolution would have meant the Terra Nova impairment charge was not required. In the fourth quarter of 2021, a further impairment charge of $25.0 million was recorded on non-core assets.

Murphy had commitments for capital expenditures of approximately $520.1 million at December 31, 2021 (2020: $747.0 million). This amount includes $175.9 million for approved expenditure for capital projects relating to non-operated interests in deepwater U.S. Gulf of Mexico, principally at St. Malo ($173.0 million), non-operated Canada interests, mainly offshore ($84.7 million), non-operated Eagle Ford Shale ($18.1 million), Brazil ($16.3 million), Vietnam ($6.1 million), and Brunei ($2.6 million).

Assets held for sale of $15.5 million decreased $312.3 million due to the March 2021 sale of King’s Quay FPS to ArcLight Capital Partners, LLC (ArcLight) for proceeds of $267.7 million.

Operating lease assets ($881.4 million) and liabilities ($900.6 million) decreased $46.3 million principally due to an annual charge of depreciation, depletion and amortization and 2021 annual payments reducing the operating lease liabilities.

Long-term asset retirement obligations increased $23.5 million to $839.8 million, principally due to inflationary pressures from higher oil prices and associated demand for services.

Deferred credits and other liabilities decreased $110.0 million primarily as a result of the pension fair value remeasurement and cash pension contributions to the plan in 2021.

At December 31, 2021, the Company had no outstanding borrowings under the RCF and $31.4 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%. Note that 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. Some USD LIBOR tenors (overnight, 1-month, 3-month, 6-month and 12-month) will continue to be published until June 30, 2023. See “Risk Factors – Financial Risk Factors – Capital Financing” for further discussion. 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, 2021, the interest rate in effect on borrowings under the facility was 1.78%. At December 31, 2021, the Company was in compliance with all covenants related to the RCF.

Environmental, Health and Safety Matters

Murphy faces various environmental, health and safety 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, Environmental and Corporate Responsibility Committee consisting of certain members of Murphy's Board of Directors.

The oil and natural gas industry is subject to numerous international, foreign, national, state, provincial and local environmental, health and safety laws and regulations. Murphy allocates a portion of both its capital expenditures and its general and administrative budget toward compliance with existing and anticipated environmental, health and safety 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, health and safety 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; the emission and discharge of such materials to the environment, including GHG emissions; wildlife, habitat and water protection; the placement, operation and decommissioning of production equipment; and the health and safety of our employees, contractors and communities where our operations are located. These laws and regulations also generally require 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.

Further information on environmental, health and safety laws and regulations applicable to Murphy are contained in the Business section beginning page 11.

Climate Change and Emissions

The world's population and standard of living is growing steadily along with the demand for energy. Murphy recognizes that this may generate increasing amounts of greenhouse gases, which raise important climate change concerns. Murphy works to assess the Company's governance, strategy, risk identification, and management and measurement of climate risks and opportunities in order to remain in alignment with the Task Force on Climate-related Financial Disclosures (TCFD) core elements. The TCFD was created by the Financial Stability Board to focus on climate-related financial disclosures to improve and increase reporting of climate-related financial information. Murphy's disclosures related to its alignment with the TCFD are included in the Company's 2021 Sustainability Report issued on August 5, 2021, which is not incorporated by reference hereto.

During 2021 the Company made significant strides in our sustainability efforts, including:

- Setting a goal to achieve zero routine flaring by 2030;
- Obtaining third-party assurance of our 2020 Scope 1 and 2 gross-operated GHG emissions;
- Decreasing our 2020 Scope 1 and 2 GHG emissions intensity by 10% from our 2019 baseline;
- Publishing our estimated Scope 3, Category 11 - Use of Sold Products GHG emissions;
- Updating our 2008 established climate change position;
- Adding an annual GHG emissions intensity goal as a performance metric, to the already established safety and spills metrics, in our Company's renumeration policy; and
- Including processes to stress-test our GHG emissions under various portfolio scenarios.

During 2020, the Company:

- Established a goal of reducing our GHG emissions intensity 15% to 20% by 2030 from our 2019 levels, excluding divested assets from the 2019 baseline, for an aggregate of 35% to 40% reduction from our reported 2019 levels;
- Expanded our GHG, air quality, climate risk management and biodiversity management public disclosures;
- Expanded the purview of our Health, Safety, Environmental and Corporate Responsibility Committee to include sustainability issues; and
- Created a Director of Sustainability role

Other Matters

Impact of inflation – In 2021, data indicates a sharp rise in inflation globally in most countries where the Company operates (this follows a sustained period of relatively low inflation prior to 2021). In the U.S. (and other parts of the globe), inflation has been triggered by constrained supplies and increasing demand of certain goods and services as recovery from the COVID-19 pandemic begins. The Company’s revenues, capital and operating costs are influenced to a larger extent by specific price changes in the oil and natural gas industry and allied industries rather 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.

As a result of increasing commodity prices for oil and natural gas, in 2021 and at the start of 2022, higher costs for goods and services in the oil and gas natural gas industry are being observed. Murphy has a dedicated procurement department focused on managing supply chain and input costs. Murphy also has certain transportation, processing and production handling services costs fixed through long-term contracts and commitments and therefore is partly protected from increasing price of services. However, from time to time, Murphy will seek to enter new commitments, exercise options to extend contracts and retender contracts for rigs and other industry services which could expose Murphy to the impact of higher prices. Murphy continues to strive toward safely executing our work in an ever increasing efficient manner to mitigate possible inflationary pressures in our business.

In 2020, some downward service cost relief was observed during a year of depressed commodity prices.

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 can be restricted to specific geographic areas. Natural gas demand is also impacted by demand driven by lower carbon emission and a view that natural gas is one option to transition from higher carbon emitting fuels.

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.

Critical Accounting Estimates – 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 110 to 119 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, 2021 beginning on pages 4 and 110 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.

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, health and safety laws and 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.

In 2021 and 2020, the Company recognized pretax noncash impairment charges of $196.3 million and $1,206.3 million, respectively, to reduce the carrying values at select properties. In 2021, the Company recorded an impairment charge of $171.3 million for Terra Nova due to the status, including agreements with the partners, of operating and production plans and $25.0 million for assets reported as Assets held for sale in the Consolidated Balance Sheets.

In 2020, declines in future oil and natural gas prices (principally driven by reduced commodity demand in response to the COVID-19 pandemic and increased supply in the first quarter of 2020 from foreign oil producers) led to impairments in certain of the Company's U.S. Offshore and Other Foreign properties and assets.

See also Note D – Property, Plant and Equipment for further discussion of impairment charges.

Income taxes – The Company is subject to income and other similar taxes in all areas in which it operates. When recording income tax expense, certain estimates are required because: (a) income tax returns are generally filed months after the close of its annual accounting period; (b) tax returns are subject to audit by taxing authorities and audits can often take years to complete and settle; (c) future events often impact the timing of when income tax expenses and benefits are recognized by the Company; and (d) changes to regulations may be subject to different interpretations and require future clarification from issuing authorities or others.

The Company has deferred tax assets mostly relating to U.S net operating losses, liabilities for dismantlement, retirement benefit plan obligations and net deferred tax liabilities relating to tax and accounting basis differences for property, plant & equipment.

The Company routinely evaluates all deferred tax assets to determine the likelihood of their realization and reduce such assets to the expected realizable amount by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. In assessing the need for valuation allowances, we consider all available positive and negative evidence. Positive evidence includes projected future taxable income and assessment of future business assumptions, a history of utilizing tax assets before expiration, significant proven and probable reserves and reversals of taxable temporary differences. Negative evidence includes losses in recent years.

As of December 31, 2021 the Company had a U.S. deferred tax asset associated with net operating losses of $577.5 million. In reviewing the likeliness of realizing this asset the Company considered the reversal of taxable temporary differences, carryforward periods, and future taxable income estimates based on projected financial information which, based on currently available evidence, we believe to be reasonably likely to occur. Certain estimates and assumptions are used in the estimation of future taxable income, including (but not limited to) (a) future commodity prices for crude oil and condensate, NGLs and natural gas, (b) estimated reserves for crude oil and condensate, NGLs and natural gas, (c) expected timing of production, (d) estimated lease operating costs, and (e) future capital requirements. In the future, the underlying actual assumptions utilized in estimating future taxable income could be different and result in different conclusions about the likelihood of the future utilization of our net operating loss carryforwards.

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 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 as of December 31, 2021, the Company has used a weighted average discount rate of 2.83% at year-end 2021 for the primary U.S. plans. This weighted average discount rate is 0.4% higher than prior year, which decreased the Company's recorded liabilities for retirement plans compared to a year ago. The Company presently assumes a return on plan assets of 5.25% for the primary U.S. plan, it periodically reconsiders the appropriateness of this and other key assumptions. The Company's retirement and postretirement plan (health care and life insurance benefit plans) expenses in 2022 are expected to be $9.9 million lower than 2021 primarily due to the increase in expected return assumptions for the US pension plan from 5.25% in 2021 to 6.60% in 2022, coupled with the impact of 2021 pension plan gain on reducing the amount of accumulated loss to be amortized as expense. Cash contributions to all plans are anticipated to be $5.5 million higher in 2022.

In 2021, the Company paid $36.5 million into various retirement plans and $1.1 million into postretirement plans. In 2022, the Company is expecting to fund payments of approximately $38.2 million into various retirement plans and $4.9 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.

Recent Accounting Pronouncements

See Note B – New Accounting Principles and Recent Accounting Pronouncements our Consolidated Financial Statements regarding the impact or potential impact of recent accounting pronouncements upon our financial position and results of operations.

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 2021 under such contractual obligations and arrangements are shown in the table below. Amounts are undiscounted and therefore may differ to those presented in the financial statements.

	Amount of Obligations				
(Millions of dollars)	**Total**	2022	2023 - 2024	2025 - 2026	After 2026
Debt, excluding interest	**$ 2,483.3**	—	242.4	548.7	1,692.2
Operating leases and other leases [1]	**1,258.5**	185.9	272.5	148.9	651.2
Capital expenditures, drilling rigs and other [2]	**1,572.9**	704.2	340.1	172.2	356.4
Other long-term liabilities, including debt interest [3]	**2,747.2**	195.7	353.8	456.0	1,741.7
Total	**$ 8,061.9**	1,085.8	1,208.8	1,325.8	4,441.5

[1] Other leases refers to a finance lease in Brunei (see Note U – Leases to the financial statements).
[2] Capital expenditures, drilling rigs and other includes $175.9 million, $84.7 million, $24.9 million, and $18.1 million in 2022 for approved capital projects in non-operated interests in U.S. Gulf of Mexico, Canada Offshore, Other Foreign Offshore, and U.S. Onshore, respectively.
Also includes $72.0 million (2022), $129.5 million (2023 - 2024), $98.2 million (2025 - 2026) and $227.7 million (After 2026) for pipeline transportation commitments in Canada.
Also includes $4.5 million (2022), $10.7 million (2023 - 2024), $10.3 million (2025 - 2026) and $32.3 million (After 2026) 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 as well as 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 $223.5 million as of December 31, 2021.

Material off-balance sheet arrangements – Certain U.S. transportation contracts require minimum monthly payments through 2045, while Western Canada processing contracts call for minimum monthly payments through 2051. 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 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 close on February 24, 2022, the NYMEX WTI forward curve price for the remainder of 2022 and 2023 were $86.31 and $77.72 per barrel, respectively; however we cannot predict what impact economic factors (including the ongoing COVID-19 pandemic and OPEC+ decisions) may have on future commodity pricing. Lower prices, should they occur, will result in lower profits and operating cash-flows.

The Company's capital expenditure spend for 2022 is expected to be between $840.0 million and $890.0 million, excluding the amount attributable to noncontrolling interest. Capital and other expenditures are routinely reviewed and planned capital expenditures may be adjusted to reflect differences between budgeted and forecast 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 2022 using operating cash flow and available cash. 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 under available credit facilities might be required during the year to maintain funding of the Company's ongoing development projects.

The Company currently expects average daily production in 2022 to be between 172,600 and 180,600 barrels of oil equivalent per day (including noncontrolling interest of 8,600 BOEPD). If significant price declines occur, the Company will review the option of production curtailments to avoid incurring losses on certain produced barrels.

The Company plans to utilize surplus cash (not planned to be used by operations, investing activities, or payment to noncontrolling interests) to repay outstanding debt and return to shareholders through dividends.

The Company continues to monitor the impact of commodity prices on its financial position and is currently in compliance with the covenants related to the revolving credit facility (see Note G – Financing Arrangements and Debt). The Company continues to monitor the effects of the COVID-19 pandemic and is encouraged by the increase in oil and natural gas demand through 2021 and into 2022.

The Company has entered into derivative or forward fixed-price delivery contracts to manage risk associated with certain future oil and natural gas sales prices as follows:

Area	Commodity	Type	Volumes (MMcf/d)	Price/Mcf	Remaining Period Start Date	Remaining Period End Date
Montney	Natural Gas	Fixed price forward sales	186	C$2.36	1/1/2022	1/31/2022
Montney	Natural Gas	Fixed price forward sales	176	C$2.34	2/1/2022	4/30/2022
Montney	Natural Gas	Fixed price forward sales	205	C$2.34	5/1/2022	5/31/2022
Montney	Natural Gas	Fixed price forward sales	247	C$2.34	6/1/2022	10/31/2022
Montney	Natural Gas	Fixed price forward sales	266	C$2.36	11/1/2022	12/31/2022
Montney	Natural Gas	Fixed price forward sales	269	C$2.36	1/1/2023	3/31/2023
Montney	Natural Gas	Fixed price forward sales	250	C$2.35	4/1/2023	12/31/2023
Montney	Natural Gas	Fixed price forward sales	162	C$2.39	1/1/2024	12/31/2024
Montney	Natural Gas	Fixed price forward sales	45	US$2.05	1/1/2022	12/31/2022
Montney	Natural Gas	Fixed price forward sales	25	US$1.98	1/1/2023	10/31/2024
Montney	Natural Gas	Fixed price forward sales	15	US$1.98	11/1/2024	12/31/2024

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	20,000	$44.88	1/1/2022	12/31/2022

Area	Commodity	Type	Volumes (Bbl/d)	Average Put (USD/Bbl)	Average Call (USD/Bbl)	Remaining Period Start Date	Remaining Period End Date
United States	WTI [1]	Derivative collars	25,000	$63.24	$75.20	1/1/2022	12/31/2022

[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. Forward-looking statements are generally identified through the inclusion of words such as “aim”, “anticipate”, “believe”, “drive”, “estimate”, “expect”, “expressed confidence”, “forecast”, “future”, “goal”, “guidance”, “intend”, “may”, “objective”, “outlook”, “plan”, “position”, “potential”, “project”, “seek”, “should”, “strategy”, “target”, “will” or variations of such words and other similar expressions. These statements, which express management’s current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause one or more of these future events or results not to occur as implied by any forward-looking statement include, but are not limited to: macro conditions in the oil and gas industry, including supply/demand levels, actions taken by major oil exporters and the resulting impacts on commodity prices; increased volatility or deterioration in the success rate of our exploration programs or in our ability to maintain production rates and replace reserves; reduced customer demand for our products due to environmental, regulatory, technological or other reasons; adverse foreign exchange movements; political and regulatory instability in the markets where we do business; the impact on our operations or market of health pandemics such as COVID-19 and related government responses; other natural hazards impacting our operations or markets; any other deterioration in our business, markets or prospects; any failure to obtain necessary regulatory approvals; any inability to service or refinance our outstanding debt or to access debt markets at acceptable prices; or adverse developments in the U.S. or global capital markets, credit markets or economies in general. For further discussion of factors that could cause one or more of these future events or results not to occur as implied by any forward-looking statement, see Item 1A. Risk Factors, which begins on page 15 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 L – Financial Instruments and Risk Management, Murphy makes use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions.

There were commodity transactions in place as of December 31, 2021, covering certain future U.S. crude oil sales volumes in 2022. A 10% increase in the respective benchmark price of these commodities would have increased the net payable associated with these derivative contracts by approximately $100.9 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 as of December 31, 2021.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages 63 through 128 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, 2021, 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, 2021. 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, 2021 and their report is included on page 67 of this Form 10-K report.

There were no changes in the Company's internal controls over financial reporting that occurred during the fourth quarter of 2021 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. OTHER INFORMATION

None

Item 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Certain information regarding executive officers of the Company is included on page 28 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 11, 2022 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 9805 Katy Fwy, Suite G-200, Houston, TX 77024. 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 11, 2022 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 11, 2022 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 11, 2022 under the caption "Election of Directors."

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Our independent registered public accounting firm is KPMG LLP, Houston, TX, Auditor Firm ID: 185.

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 11, 2022 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	Exhibit 4.9 to Form 10-K filed on February 27, 2020

10.1	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
10.2	Murphy Oil Corporation 2017 Annual Incentive Plan	Exhibit A to definitive proxy statement filed March 28, 2016
*10.3	Murphy Oil Corporation Annual Incentive Plan	
10.4	Murphy Oil Corporation 2012 Long-Term Incentive Plan	Exhibit A to definitive proxy statement filed March 29, 2012
10.5	Amendment to the Murphy Oil Corporation 2012 Long-Term Incentive Plan	Exhibit 10.8 to Form 10-K filed on February 27, 2020
10.6	Form of employee stock option (2012 Long-Term Plan)	Exhibit 99.1 to Form 10-K for the year ended December 31, 2013
10.7	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
10.8	Form of stock appreciation right (2012 Long-Term Plan)	Exhibit 99.3 to Form 10-Q filed May 7, 2014
10.9	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
10.10	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
10.11	Murphy Oil Corporation 2018 Long-Term Incentive Plan	Exhibit B to definitive proxy statement filed March 23, 2018
10.12	Amendment to the Murphy Oil Corporation 2018 Long-Term Incentive Plan	Exhibit 10.15 to Form 10-K filed on February 27, 2020
10.13	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
10.14	Form of employee performance-based restricted stock unit – stock settled grant agreement (2018 Long-Term Plan)	Exhibit 10.17 to Form 10-K filed on February 27, 2020
10.15	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
10.16	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
10.17	Murphy Oil Corporation 2020 Long-Term Incentive Plan	Exhibit A to definitive proxy statement filed March 30, 2020
10.18	Form of employee performance-based restricted stock unit – stock settled grant agreement (2020 LTI Plan)	Exhibit 10.21 to Form 10-K filed on February 26, 2021
10.19	Form of employee time-based restricted stock unit – stock settled 3-year grant agreement (2020 LTI Plan)	Exhibit 10.22 to Form 10-K filed on February 26, 2021
10.20	Form of employee time-based restricted stock unit – stock settled 5-year grant agreement (2020 LTI Plan)	Exhibit 10.23 to Form 10-K filed on February 26, 2021
10.21	Form of employee time-based restricted stock unit – cash settled 3-year grant agreement (2020 LTI Plan)	Exhibit 10.24 to Form 10-K filed on February 26, 2021
10.22	Form of employee time-based restricted stock unit – cash settled 5-year grant agreement (2020 LTI Plan)	Exhibit 10.25 to Form 10-K filed on February 26, 2021

10.23	Murphy Oil Corporation 2013 Stock Plan for Non-Employee Directors	Exhibit A to definitive proxy statement filed March 22, 2013
10.24	Form of non-employee director restricted stock unit award (2013 NED Plan)	Exhibit 99.2 to Form 10-Q filed November 6, 2013
10.25	Murphy Oil Corporation 2018 Stock Plan for Non-Employee Directors	Exhibit A to definitive proxy statement filed March 23, 2018
10.26	First Amendment to the 2018 Stock Plan for Non-Employee Directors	Exhibit 10.1 to Form 8-K filed April 25, 2018
10.27	Second Amendment to the 2018 Stock Plan for Non-Employee Directors	Exhibit 10.24 to Form 10-K filed on February 27, 2020
10.28	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
10.29	Form of non-employee director restricted stock unit award – stock settled grant agreement (2018 NED Plan)	Exhibit 10.26 to Form 10-K filed on February 27, 2020
10.30	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
10.31	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
10.32	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
10.33	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 Roger W. Jenkins, President	Date:	February 25, 2022

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 25, 2022 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ CLAIBORNE P. DEMING Claiborne P. Deming, Chairman and Director	/s/ JAMES V. KELLEY James V. Kelley, Director
/s/ ROGER W. JENKINS Roger W. Jenkins, President and Chief Executive Officer and Director (Principal Executive Officer)	/s/ R. MADISON MURPHY R. Madison Murphy, Director
/s/ T. JAY COLLINS T. Jay Collins, Director	/s/ JEFFREY W. NOLAN Jeffrey W. Nolan, Director
/s/ STEVEN A. COSSE Steven A. Cossé, Director	/s/ ROBERT N. RYAN, JR. Robert N. Ryan, Jr., Director
/s/ LAWRENCE R. DICKERSON Lawrence R. Dickerson, Director	/s/ NEAL E. SCHMALE Neal E. Schmale, Director
/s/ MICHELLE A. EARLEY Michelle A. Earley, Director	/s/ LAURA A. SUGG Laura A. Sugg, Director
/s/ ELISABETH W. KELLER Elisabeth W. Keller, Director	/s/ DAVID R. LOONEY 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 (PCAOB) 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 64.

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, 2021.

KPMG LLP has performed an audit of the Company's internal control over financial reporting, and their opinion thereon can be found on page 67.

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, 2021 and 2020, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2021, 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, 2021, 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 25, 2022 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

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.

Estimated oil and gas reserves used in the depletion of producing 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. 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 by 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. For the year ended

December 31, 2021, the Company recorded depreciation, depletion, and amortization expense of $795.1 million.

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

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's depletion calculation process, including controls related to the estimation of proved oil and gas reserves. We evaluated (1) the professional qualifications of the internal petroleum reserve engineers, third-party petroleum reserve specialists, and external engineering firm, (2) the knowledge, skills, ability of the Company's internal petroleum reserve engineers and third-party petroleum reserve specialists, and (3) the relationship of the third-party petroleum reserve specialists and external engineering firm to 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.

Evaluation of the realizability of deferred tax assets

As discussed in Note I to the consolidated financial statements, the Company had gross deferred tax assets of $1,147.1 million, which includes a deferred tax asset for U.S. net operating losses of $577.5 million, as of December 31, 2021. A valuation allowance is provided for deferred tax assets if it is more likely than not that all or a portion of these deferred tax assets will not be realized in a future period, which is dependent upon the generation of taxable income.

We identified the evaluation of the realizability of deferred tax assets as a critical audit matter. The evaluation of the realizability of deferred tax assets, especially those related to U.S. net operating loss carryforwards, required subjective auditor judgment to assess the application of tax laws and the projections of future taxable income over the periods in which those temporary differences become deductible. Changes in assumptions regarding future taxable income could have a significant impact on the Company's evaluation of the realizability of the deferred tax assets.
The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Company's evaluation of the realizability of deferred tax assets, including controls related to the application of tax laws and the development of projections of future taxable income. We evaluated the assumptions used in the development of projected future taxable income by comparing such assumptions to estimated oil and gas reserve quantities developed by the Company, by comparing projected cost estimates to historical actual costs, and by comparing future commodity prices used in the determination of projected future taxable income to external sources. We also evaluated the Company's history of realizing deferred tax assets by evaluating the expiration of net operating loss carryforwards and testing the reversal pattern of taxable temporary differences. We involved income tax professionals with specialized skills and knowledge who assisted in assessing the Company's application of tax laws.

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 the uncertainty associated with future commodity prices and estimated oil and gas reserves 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 triggering event 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 reserve specialists engaged by the Company to evaluate the estimated proved oil and gas reserves.

/s/ KPMG LLP

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

Houston, Texas
February 25, 2022

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, 2021, 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, 2021, 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, 2021 and 2020, 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, 2021, and the related notes and financial statement schedule II (collectively, the consolidated financial statements), and our report dated February 25, 2022 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 25, 2022

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31 (Thousands of dollars except share amounts)		2021	2020
ASSETS			
Current assets			
Cash and cash equivalents		$ **521,184**	310,606
Accounts receivable, net		**258,150**	262,014
Inventories	Note F	**54,198**	66,076
Prepaid expenses		**31,925**	33,860
Assets held for sale	Note E	**15,453**	327,736
Total current assets		**880,910**	1,000,292
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $12,457,851 in 2021 and $11,455,305 in 2020	Note D	**8,127,852**	8,269,038
Operating lease assets	Note U	**881,389**	927,658
Deferred income taxes	Note I	**385,516**	395,253
Deferred charges and other assets		**29,273**	28,611
Total assets		$ **10,304,940**	10,620,852
LIABILITIES AND EQUITY			
Current liabilities			
Current maturities of long-term debt, finance lease		$ **654**	—
Accounts payable		**623,129**	407,097
Income taxes payable		**19,951**	18,018
Other taxes payable		**20,306**	22,498
Operating lease liabilities		**139,427**	103,758
Other accrued liabilities		**360,859**	150,578
Liabilities associated with assets held for sale	Note E	**—**	14,372
Total current liabilities		**1,164,326**	716,321
Long-term debt, including finance lease obligation	Note G	**2,465,414**	2,988,067
Asset retirement obligations	Note H	**839,776**	816,308
Deferred credits and other liabilities		**570,574**	680,580
Non-current operating lease liabilities	Note U	**761,162**	845,088
Deferred income taxes	Note I	**182,892**	180,341
Total liabilities		**5,984,144**	6,226,705
Equity			
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued		**—**	—
Common Stock, par $1.00, authorized 450,000,000 shares, issued 195,100,628 shares in 2021 and 195,100,628 shares in 2020		**195,101**	195,101
Capital in excess of par value		**926,698**	941,692
Retained earnings		**5,218,670**	5,369,538
Accumulated other comprehensive loss	Note O	**(527,711)**	(601,333)
Treasury stock		**(1,655,447)**	(1,690,661)
Murphy Shareholders' Equity		**4,157,311**	4,214,337
Noncontrolling interest		**163,485**	179,810
Total equity		**4,320,796**	4,394,147
Total liabilities and equity		$ **10,304,940**	10,620,852

See Notes to Consolidated Financial Statements, page 73.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

Years Ended December 31 (Thousands of dollars except per share amounts)		2021	2020	2019
Revenues and other income				
Revenue from sales to customers	$	**2,801,215**	1,751,709	2,817,111
(Loss) gain on derivative instruments		**(525,850)**	202,661	(856)
Gain on sale of assets and other income		**23,916**	12,971	12,798
Total revenues and other income		**2,299,281**	1,967,341	2,829,053
Costs and expenses				
Lease operating expenses		**539,546**	600,076	605,180
Severance and ad valorem taxes		**41,212**	28,526	47,959
Transportation, gathering and processing		**187,028**	172,399	176,315
Exploration expenses, including undeveloped lease amortization		**69,044**	86,479	95,105
Selling and general expenses		**121,950**	140,243	232,736
Restructuring expenses		**—**	49,994	—
Depreciation, depletion and amortization		**795,105**	987,239	1,147,842
Accretion of asset retirement obligations		**46,613**	42,136	40,506
Impairment of assets		**196,296**	1,206,284	—
Other (benefit) expense		**21,052**	16,274	38,117
Total costs and expenses		**2,017,846**	3,329,650	2,383,760
Operating income (loss) from continuing operations		**281,435**	(1,362,309)	445,293
Other income (loss)				
Interest income and other (loss)		**(16,771)**	(17,303)	(22,520)
Interest expense, net		**(221,773)**	(169,423)	(219,275)
Total other loss		**(238,544)**	(186,726)	(241,795)
Income (loss) from continuing operations before income taxes		**42,891**	(1,549,035)	203,498
Income tax expense (benefit)		**(5,862)**	(293,741)	14,683
Income (loss) from continuing operations		**48,753**	(1,255,294)	188,815
Income (loss) from discontinued operations, net of income taxes		**(1,225)**	(7,151)	1,064,487
Net income (loss) including noncontrolling interest		**47,528**	(1,262,445)	1,253,302
Less: Net income (loss) attributable to noncontrolling interest		**121,192**	(113,668)	103,570
NET INCOME (LOSS) ATTRIBUTABLE TO MURPHY	$	**(73,664)**	(1,148,777)	1,149,732
INCOME (LOSS) PER COMMON SHARE – BASIC				
Continuing operations	$	**(0.47)**	(7.43)	0.52
Discontinued operations		**(0.01)**	(0.05)	6.49
Net income (loss)	$	**(0.48)**	(7.48)	7.01
INCOME (LOSS) PER COMMON SHARE – DILUTED				
Continuing operations	$	**(0.47)**	(7.43)	0.52
Discontinued operations		**(0.01)**	(0.05)	6.46
Net income (loss)	$	**(0.48)**	(7.48)	6.98
Cash dividends per Common share	$	**0.50**	0.625	1.00
Average Common shares outstanding (thousands)				
Basic		**154,291**	153,507	163,992
Diluted		**154,291**	153,507	164,812

See Notes to Consolidated Financial Statements, page 73.

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

Years Ended December 31 (Thousands of dollars)		2021	2020	2019
Net income (loss) including noncontrolling interest	$	**47,528**	(1,262,445)	1,253,302
Other comprehensive income (loss), net of tax				
Net gain (loss) from foreign currency translation		**12,116**	29,241	66,600
Retirement and postretirement benefit plans		**59,816**	(57,617)	(35,979)
Deferred loss on interest rate hedges reclassified to interest expense		**1,690**	1,204	5,005
Other comprehensive income (loss)		**73,622**	(27,172)	35,626
Comprehensive income (loss)		**121,150**	(1,289,617)	1,288,928
Comprehensive income (loss) attributable to noncontrolling interest		**(121,192)**	113,668	(103,570)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO MURPHY	$	**(42)**	(1,175,949)	1,185,358

See Notes to Consolidated Financial Statements, page 73.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 (Thousands of dollars)	2021	2020	2019
Operating Activities			
Net income (loss) including noncontrolling interest	$ **47,528**	(1,262,445)	1,253,302
Adjustments to reconcile net income (loss) to net cash provided by continuing operations activities			
Depreciation, depletion and amortization	**795,105**	987,239	1,147,842
Impairment of assets	**196,296**	1,206,284	—
Mark to market loss on derivative instruments	**112,113**	69,310	33,364
Mark to market loss (gain) on contingent consideration	**63,147**	(13,783)	8,672
Long-term non-cash compensation	**63,382**	46,558	76,958
Accretion of asset retirement obligations	**46,613**	42,136	40,506
Amortization of undeveloped leases	**18,925**	26,743	27,973
Previously suspended exploration costs	**17,339**	21,099	12,840
Deferred income tax (benefit) expense	**(4,146)**	(278,042)	28,530
Loss (income) from discontinued operations	**1,225**	7,151	(1,064,487)
Net decrease (increase) in noncash working capital	**118,457**	(32,027)	(16,887)
Other operating activities, net	**(53,821)**	(35,080)	(59,508)
Noncash restructuring expense	**—**	17,565	—
Net cash provided by continuing operations activities	**1,422,163**	802,708	1,489,105
Investing Activities			
Property additions and dry hole costs	**(670,479)**	(759,809)	(1,244,069)
Proceeds from sales of property, plant and equipment	**270,503**	13,750	20,382
Property additions for King's Quay FPS	**(17,734)**	(112,961)	(100,202)
Acquisition of oil and natural gas properties	—	—	(1,212,315)
Net cash required by investing activities	**(417,710)**	(859,020)	(2,536,204)
Financing Activities			
Retirement of debt	**(876,358)**	(12,225)	(521,332)
Debt issuance, net of cost	**541,913**	(613)	542,394
Repayment of revolving credit facility	**(365,000)**	(250,000)	(2,050,000)
Borrowings on revolving credit facility	**165,000**	450,000	1,725,000
Distributions to noncontrolling interest	**(137,517)**	(43,673)	(128,158)
Cash dividends paid	**(77,204)**	(95,989)	(163,669)
Early redemption of debt cost	**(39,335)**	—	(26,626)
Withholding tax on stock-based incentive awards	**(5,209)**	(7,094)	(6,991)
Capital lease obligation payments	**(803)**	(695)	(688)
Repurchase of common stock	**—**	—	(499,924)
Net cash (required) provided by financing activities	**(794,513)**	39,711	(1,129,994)
Cash Flows from Discontinued Operations [1]			
Operating activities	**—**	(1,202)	73,783
Investing activities	**—**	4,494	2,022,034
Financing activities	**—**	—	(4,914)
Net cash provided by discontinued operations	**—**	3,292	2,090,903
Cash from discontinued operations	**—**	18,438	2,120,397
Effect of exchange rate changes on cash and cash equivalents	**638**	2,009	3,533
Net increase in cash and cash equivalents	**210,578**	3,846	(53,163)
Cash and cash equivalents at beginning of period	**310,606**	306,760	359,923
Cash and cash equivalents at end of period	$ **521,184**	**310,606**	**306,760**

[1] Net cash provided by discontinued operations are not part of the cash flow reconciliation.
See Notes to Consolidated Financial Statements, page 73.

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

Years Ended December 31 (Thousands of dollars except number of shares)	2021	2020	2019
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	$ —	—	—
Common Stock – par $1.00, authorized 450,000,000 shares at December 31, 2021, 2020 and 2019, issued 195,100,628 at December 31, 2021, 195,100,628 shares at December 31, 2020 and 195,089,269 at December 31, 2019			
Balance at beginning of year	**195,101**	195,089	195,077
Exercise of stock options	**—**	12	12
Balance at end of year	**195,101**	195,101	195,089
Capital in Excess of Par Value			
Balance at beginning of year	**941,692**	949,445	979,642
Stock-based compensation	**25,429**	26,052	33,235
Restricted stock transactions and other	**(38,749)**	(33,649)	(38,731)
Exercise of stock options, including income tax benefits	**(1,674)**	(156)	(182)
Fair value increase in common controlled assets	**—**	—	(24,519)
Balance at end of year	**926,698**	941,692	949,445
Retained Earnings			
Balance at beginning of year	**5,369,538**	6,614,304	5,513,529
Net income (loss) for the year attributable to Murphy	**(73,664)**	(1,148,777)	1,149,732
Cash dividends	**(77,204)**	(95,989)	(163,669)
Sale and leaseback gain recognized upon adoption of ASC 842, net of tax impact	**—**	—	114,712
Balance at end of year	**5,218,670**	5,369,538	6,614,304
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(601,333)**	(574,161)	(609,787)
Foreign currency translation gains (losses), net of income taxes	**12,116**	29,241	66,600
Retirement and postretirement benefit plans, net of income taxes	**59,816**	(57,617)	(35,979)
Deferred loss on interest rate hedge reclassified to interest expense, net of income taxes	**1,690**	1,204	5,005
Balance at end of year	**(527,711)**	(601,333)	(574,161)
Treasury Stock			
Balance at beginning of year	**(1,690,661)**	(1,717,217)	(1,249,162)
Awarded restricted stock, net of forfeitures	**33,888**	26,556	31,869
Exercise of stock options	**1,326**	—	—
Purchase of treasury shares	**—**	—	(499,924)
Balance at end of year – 40,637,578 of Common Stock in 2021, 41,502,003 shares of Common Stock in 2020, and 42,153,908 shares of Common Stock in 2019	**(1,655,447)**	(1,690,661)	(1,717,217)
Murphy Shareholders' Equity	**4,157,311**	4,214,337	5,467,460
Noncontrolling Interest			
Balance at beginning of year	**179,810**	337,151	368,343
Net income (loss) attributable to noncontrolling interest	**121,192**	(113,668)	103,570
Distributions to noncontrolling interest owners	**(137,517)**	(43,673)	(128,158)
Acquisition closing adjustments	—	—	(6,604)
Balance at end of year	**163,485**	179,810	337,151
Total Equity	**$ 4,320,796**	4,394,147	5,804,611

See Notes to Consolidated Financial Statements, page 73.

These notes are an integral part of the consolidated financial statements of Murphy Oil Corporation and Consolidated Subsidiaries (Murphy/the Company) on pages 68-72 of the Form 10-K report.

Note A – Significant Accounting Polices

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 Malaysian assets in 2019, and they are reported as discontinued operations.

In connection with the LLOG Exploration Offshore L.L.C. and LLOG Bluewater Holdings, L.L.C., (LLOG) acquisition, we hold a 0.5% interest in two variable interest entities (VIEs), Delta House Oil and Gas Lateral LLC and Delta House Floating Production System (FPS) LLC (collectively Delta House). These VIEs have not been consolidated because we are not considered the primary beneficiary. These non-consolidated VIEs are not material to our financial position or results of operations. As of December 31, 2021, our maximum exposure to loss was $3.4 million (excluding operational impacts), which represents our net investment in Delta House. We have not provided any financial support to Delta House other than amounts previously required by our membership interest.

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. Other investments are generally carried at cost. Intercompany accounts and transactions are 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, 2021 and 2020, 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.

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, 2021 and 2020, the Company's accounts receivable primarily consisted of amounts owed to the Company by customers for sales of crude oil and natural gas and operating costs related to joint venture partners working interest share. 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, joint venture partners, 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. See Note F.

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. In 2021 and 2020, the Company recognized pretax noncash impairment charges of $196.3 million and $1,206.3 million, respectively, to reduce the carrying values at select properties. In 2021, the Company recorded an impairment charge of $171.3 million for Terra Nova due to the status, including agreements with the partners, of operating and production plans and $25.0 million for assets reported as Assets held for sale in the Consolidated Balance Sheets. See also Note D 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. See Note H.

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 (related to Brunei) are presented on the Consolidated Balance Sheet within Property, plant and equipment 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.

The accounting rules for income tax uncertainties permit recognition of income tax benefits only when they are more likely than not to be 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. All commodity price derivatives for the periods provided are not designated as cash flow or fair value hedges and therefore changes in fair value are recognized 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 P.

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 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 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 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 J.

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 K.

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

Compensation-Retirement Benefits-Defined Benefit Plans-General. In August 2018, the Financial Accounting Standards Board (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 ending after December 15, 2020, with early adoption permitted, and is to be applied on a retrospective basis to all periods presented. The Company adopted the standard in the fourth quarter of 2020, and it did not have a material impact on its consolidated financial statements.

Financial Instruments – Credit Losses. In June 2016, the FASB issued Accounting Standards Update (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. The Company adopted this guidance in the first quarter of 2021, and it did not have a material impact on its consolidated financial statements.

Recent Accounting Pronouncements

None affecting the Company.

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 gas) in select basins around the globe. The Company's revenue from sales of oil and 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 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 U.S. GAAP.

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

Canada - In Canada, contracts include long-term floating commodity index priced and 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.

Disaggregation of Revenue

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

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

For the years ended December 31, 2021, 2020, and 2019 the Company recognized $2,801.2 million, $1,751.7 million and $2,817.1 million, respectively, from contracts with customers for the sales of oil, natural gas liquids and natural gas.

		Years Ended December 31,		
(Thousands of dollars)		**2021**	2020	2019
Net crude oil and condensate revenue				
United States	Onshore	$ **626,136**	353,311	750,278
	Offshore	**1,478,993**	940,265	1,477,816
Canada	Onshore	**119,799**	93,591	116,174
	Offshore	**92,741**	71,495	159,254
Other		**4,924**	1,806	11,642
Total crude oil and condensate revenue		**2,322,593**	1,460,468	2,515,164
Net natural gas liquids revenue				
United States	Onshore	**50,189**	22,504	30,615
	Offshore	**44,411**	19,749	26,968
Canada	Onshore	**16,375**	8,921	12,001
Total natural gas liquids revenue		**110,975**	51,174	69,584
Net natural gas revenue				
United States	Onshore	**39,803**	20,132	27,668
	Offshore	**81,944**	49,300	46,259
Canada	Onshore	**245,900**	170,635	158,436
Total natural gas revenue		**367,647**	240,067	232,363
Total revenue from contracts with customers [1]		**2,801,215**	1,751,709	2,817,111
Gain (loss) on crude contracts		**(525,850)**	202,661	(856)
Gain on sale of assets and other income [2]		**23,916**	12,971	12,798
Total revenue and other income		$ **2,299,281**	1,967,341	2,829,053

[1] Includes revenue attributable to noncontrolling interest in MP GOM.
[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, 2021 and 2020, receivables from contracts with customers, net of royalties and associated payables, on the balance sheet from continuing operations, were $169.8 million and $135.2 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 a forward-looking expected loss model in accordance with ASU 2016-13, 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 revenue contracts that have financing components as of December 31, 2021, 2020 or 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 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, 2021, 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, 2021

Location	Commodity	End Date		Description	Approximate Volumes
U.S.	Natural Gas and NGL	Q1 2023		Deliveries from dedicated acreage in Eagle Ford	As produced
Canada	Natural Gas	Q4 2022		Contracts to sell natural gas at USD index pricing	8 MMCFD
Canada	Natural Gas	Q4 2022		Contracts to sell natural gas at CAD fixed prices	5 MMCFD
Canada	Natural Gas	Q4 2022		Contracts to sell natural gas at USD fixed pricing	20 MMCFD
Canada	Natural Gas	Q4 2023		Contracts to sell natural gas at USD index pricing	25 MMCFD
Canada	Natural Gas	Q4 2023	[1]	Contracts to sell natural gas at CAD fixed prices	38 MMCFD
Canada	Natural Gas	Q4 2024		Contracts to sell natural gas at USD index pricing	31 MMCFD
Canada	Natural Gas	Q4 2024		Contracts to sell natural gas at CAD fixed prices	100 MMCFD
Canada	Natural Gas	Q4 2024	[1]	Contracts to sell natural gas at CAD fixed prices	34 MMCFD
Canada	Natural Gas	Q4 2024		Contracts to sell natural gas at USD fixed pricing	15 MMCFD
Canada	Natural Gas	Q4 2026		Contracts to sell natural gas at USD index pricing	49 MMCFD
Canada	NGL	Q3 2023		Contracts to sell natural gas liquids at CAD pricing	952 MMCFD

[1] These contracts are scheduled to commence after the balance sheet date, during Q1 2022.

Fixed price contracts are accounted for as normal sales and purchases for accounting purposes.

Note D – Property, Plant and Equipment

	December 31, 2021		December 31, 2020	
(Thousands of dollars)	**Cost**	**Net**	Cost	Net
Exploration and production [1]	**$ 20,440,568**	**8,098,396** [2]	19,583,682	8,232,191 [2]
Corporate and other	**145,135**	**29,456**	140,661	36,847
Property, plant and equipment	**$ 20,585,703**	**8,127,852**	19,724,343	8,269,038
[1] Includes unproved mineral rights as follows:	**$ 615,724**	**131,107**	649,704	530,194

[2] Includes $22,543 in 2021 and $22,940 in 2020 related to administrative assets and support equipment.

Divestments

In March 2021, the King's Quay FPS was sold to ArcLight Capital Partners, LLC (ArcLight) for proceeds of $267.7 million, which reimburses the Company for previously incurred capital expenditures.

In 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. Murphy was entitled to receive a $100.0 million bonus payment contingent upon certain future exploratory drilling results prior to October 2020; however, the results were not achieved.

Acquisitions

In 2019, the Company acquired strategic deepwater Gulf of Mexico assets from LLOG Exploration Offshore L.L.C. and LLOG Bluewater Holdings, L.L.C., (LLOG). Under the terms of the transaction, Murphy paid cash consideration of $1,236.2 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 $50.0 million following first oil from certain development projects. The revenue threshold was not exceeded for 2019 or 2020; however, the threshold was met in 2021.

In 2018, the Company, through a subsidiary, acquired all of the Gulf of Mexico producing assets from Petrobras America Inc. (PAI), a subsidiary of Petrobras. Under the terms of the transaction, Murphy paid cash consideration of $780.7 million and has an obligation to pay additional contingent consideration of up to $150.0 million if certain price and production thresholds are exceeded beginning in 2019 through 2025; and $50.0 million carry for PAI development costs in the St. Malo Field if certain enhanced oil recovery projects are undertaken. The price and production thresholds were not exceeded for 2019 and 2020; however, the thresholds were met in 2021. As of December 31, 2021, Murphy had completely funded the carried interest.

Impairments

During the first quarter of 2021, the Company recorded an impairment charge of $171.3 million for Terra Nova due to the status, including agreements with the partners, of operating and production plans. Subsequently, the Company acquired an additional 7.525% working interest at Terra Nova following a commercial agreement to sanction an asset life extension project.

In the fourth quarter of 2021, the Company recorded an impairment charge of $25.0 million for assets reported as Assets held for sale in the Consolidated Balance Sheet.

In 2020, declines in future oil and natural gas prices (principally driven by reduced demand in response to the COVID-19 pandemic and increased supply in the first quarter of 2020 from foreign oil producers) led to impairments in certain of the Company's U.S. Offshore and Other Foreign properties. The Company recorded pretax noncash impairment charges of $1,206.3 million to reduce the carrying values of certain properties to their estimated fair values at the time of impairment.

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

The following table reflects the recognized before tax impairments for the three years ended December 31, 2021.

	December 31,		
(Thousands of dollars)	**2021**	2020	2019
Canada	**$ 171,296**	—	—
Other Foreign	**18,000**	39,709	—
Corporate	**7,000**	14,060	—
U.S.	**—**	1,152,515	—
	$ 196,296	1,206,284	—

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, 2021, 2020 and 2019, the Company had total capitalized drilling costs pending the determination of proved reserves of $179.5 million, $181.6 million and $217.3 million, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2021.

(Thousands of dollars)	**2021**	2020	2019
Beginning balance at January 1	**$ 181,616**	217,326	207,855
Additions pending the determination of proved reserves	**16,725**	3,999	83,712
Reclassifications to proved properties based on the determination of proved reserves	**—**	—	(61,096)
Capitalized exploration well costs charged to expense	**(18,860)**	(39,709)	(13,145)
Ending balance at December 31	**$ 179,481**	181,616	217,326

The capitalized well costs charged to expense during 2021 and 2020 principally represent charges for asset impairments (see above). 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 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.

	2021			2020			2019		
(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	**$ 13,273**	**3**	**3**	$ —	—	—	$ 63,409	5	5
One to two years	**—**	**—**	**—**	54,220	5	5	—	—	—
Two to three years	**53,070**	**5**	**5**	—	—	—	27,396	1	—
Three years or more	**113,138**	**6**	**—**	127,396	6	—	126,521	5	—
	$ 179,481	**14**	**8**	$ 181,616	11	5	$ 217,326	11	5

Of the $166.2 million of exploratory well costs capitalized more than one year at December 31, 2021, $93.1 million is in Vietnam, $45.0 million is in the U.S., $7.9 million is in Brunei, $15.3 million is in Mexico, and $4.8 million is in Canada. In all geographical areas, either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion.

Note E – Assets Held for Sale and Discontinued Operations

The following table presents the carrying value of the major categories of assets and liabilities that are reflected as held for sale on the Company's Consolidated Balance Sheets at December 31, 2021 and 2020. As of December 31, 2021, these include the net property, plant equipment of the CA-2 project in Brunei and the Company's office building in El Dorado, Arkansas. The Company's CA-1 asset in Brunei is no longer being marketed for sale. As of December 31, 2020, the balance also included $250.1 million for the King's Quay Floating Production System (FPS), which was sold in March 2021 (see Note D).

(Thousands of dollars)	**2021**	2020
Current assets		
Cash	**$ —**	10,185
Inventories	**—**	406
Property, plant, and equipment, net	**15,453**	307,704
Deferred income taxes and other assets	**—**	9,441
Total current assets associated with assets held for sale	**15,453**	327,736
Current liabilities		
Accounts payable	**—**	5,306
Other accrued liabilities	**—**	45
Current maturities of long-term debt (finance lease)	**—**	737
Taxes payable	**—**	1,510
Asset retirement obligation	**—**	261
Long-term debt (finance lease)	**—**	6,513
Total current liabilities associated with assets held for sale	**$ —**	14,372

The Company has accounted for its former Malaysian exploration and production operations and 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)	**2021**	2020	2019
Revenues [1]	**$ 795**	4,090	1,364,943
Costs and expenses			
Lease operating expense	**—**	—	127,138
Depreciation, depletion and amortization	**—**	—	33,697
Other costs and expenses (benefits)	**2,020**	11,241	81,538
Total income from discontinued operations before taxes	**(1,225)**	(7,151)	1,122,570
Income tax expense	**—**	—	58,083
Income from discontinued operations	**$ (1,225)**	(7,151)	1,064,487

[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, 2021 and 2020:

	December 31,	
(Thousands of dollars)	**2021**	2020
Unsold crude oil	**$ 15,497**	16,399
Materials and supplies	**38,701**	49,677
Inventories	**$ 54,198**	66,076

Note G – Financing Arrangements and Debt

As of December 31, 2021, 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, 2021, the Company had no outstanding borrowings under the RCF and $31.4 million of outstanding letters of credit, which reduces the borrowing capacity of the RCF. At December 31, 2021, the interest rate in effect on borrowings under the facility would have been 1.78%. At December 31, 2021, the Company was in compliance with all covenants related to the RCF.

In March 2021, the Company issued $550.0 million of new notes that bear interest at a rate of 6.375% and mature on July 15, 2028. The Company incurred transaction costs of $8.1 million on the issuance of these new notes and the Company will pay interest semi-annually on January 15 and July 15 of each year. The proceeds of the $550.0 million notes, along with cash on hand, were used to redeem and cancel $259.3 million of the Company's 4.00% notes due June 2022 and $317.1 million of the Company's 4.95% notes due December 2022 (originally issued as 3.70% notes due 2022; collectively the 2022 Notes). The cost of the debt extinguishment of $36.9 million is included in Interest expense, net on the Consolidated Statement of Operations for the year ended December 31, 2021. The cash costs of $34.2 million are shown as a financing activity on the Consolidated Statement of Cash Flows for the year ended December 31, 2021.

In August 2021, the Company redeemed $150.0 million aggregate principal amount of its 6.875% senior notes due 2024 (2024 Notes). The cost of the debt extinguishment of $3.5 million is included in Interest expense, net on the Consolidated Statement of Operations for the year ended December 31, 2021. The cash costs of $2.6 million are shown as a financing activity on the Consolidated Statement of Cash Flows for the year ended December 31, 2021.

In December 2021, the Company redeemed an additional $150.0 million aggregate principal amount of the 2024 Notes. The cost of the debt extinguishment of $3.4 million is included in Interest expense, net on the Consolidated Statement of Operations for the year ended December 31, 2021. The cash costs of $2.6 million are shown as a financing activity on the Consolidated Statement of Cash Flows for the year ended December 31, 2021.

Long-term debt consisted of the following as of December 31, 2021 and 2020:

	December 31,	
(Thousands of dollars)	**2021**	**2020**
Notes payable		
4.00% notes, due June 2022	$ **—**	259,291
4.95% notes, due December 2022 [1]	**—**	317,067
6.875% notes, due August 2024	**242,428**	542,428
5.75% notes, due August 2025	**548,675**	548,675
5.875% notes, due December 2027	**543,249**	543,249
6.375% notes, due July 2028	**550,000**	—
7.05% notes, due May 2029	**250,000**	250,000
6.375% notes, due December 2042 [1]	**349,000**	349,000
Total notes payable	**2,483,352**	2,809,710
Unamortized debt issuance cost and discount on notes payable	**(22,773)**	(21,643)
Total notes payable, net of unamortized discount	**2,460,579**	2,788,067
Capitalized lease obligation, due through March 2029 [1]	**5,489**	—
Total debt including current maturities	**2,466,068**	2,788,067
Senior Unsecured Revolving Credit Facility	**—**	200,000
Current maturities	**(654)**	—
Total long-term debt	$ **2,465,414**	2,988,067

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

Note G - Financing Arrangements and Long-Term Debt (Contd.)

The amount of long-term debt repayable over each of the next five years and thereafter are as follows: nil in 2022, nil in 2023, $242.4 million in 2024, $548.7 million in 2025, nil in 2026 and $1.69 billion thereafter.

The Company also has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through October 15, 2024.

Note H – Asset Retirement Obligations

The asset retirement obligations liabilities (ARO) recognized by the Company at December 31, 2021 and 2020 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 2021 and 2020 is shown in the following table.

(Thousands of dollars)		**2021**	2020
Balance at beginning of year	$	**849,956**	865,109
Accretion expense		**46,613**	42,136
Liabilities incurred		**54,439**	14,736
Revisions of previous estimates		**48,737**	(70,098)
Liabilities settled		**(27,824)**	(4,816)
Liabilities associated with assets held for sale		**263**	(21)
Changes due to translation of foreign currencies		**(291)**	2,910
Balance at end of year		**971,893**	849,956
Current portion of liability at end of year [1]		**(132,117)**	(33,648)
Noncurrent portion of liability at end of year	$	**839,776**	816,308

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

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.

Note I – 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)		**2021**	2020	2019
Income (loss) from continuing operations before income taxes				
United States	$	**114,659**	(1,407,598)	282,199
Foreign		**(71,768)**	(141,437)	(78,701)
Total	$	**42,891**	(1,549,035)	203,498
Income tax expense (benefit)				
U.S. Federal – Current	$	**—**	(10,627)	—
– Deferred		**(1,480)**	(249,253)	30,598
Total U.S. Federal		**(1,480)**	(259,880)	30,598
State		**3,303**	(8,413)	5,139
Foreign – Current		**(5,158)**	(5,072)	(17,823)
– Deferred		**(2,527)**	(20,376)	(3,231)
Total Foreign		**(7,685)**	(25,448)	(21,054)
Total	$	**(5,862)**	(293,741)	14,683

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

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

(Thousands of dollars)		**2021**	2020	2019
Income tax expense (benefit) based on the U.S. statutory tax rate	$	**9,007**	(325,299)	42,735
Alberta tax rate reduction and tax impact of deemed repatriation of foreign invested earnings (U.S. tax reform)		**—**	—	(17,019)
Foreign income (loss) subject to foreign tax rates different than the U.S. statutory rate		**13,270**	(3,791)	(1,122)
State income taxes, net of federal benefit		**2,500**	(6,646)	4,060
U.S. tax benefit on certain foreign upstream investments		**(8,916)**	—	(14,975)
Increase in deferred tax asset valuation allowance related to other foreign exploration expenditures		**4,814**	7,707	10,927
Tax effect on income attributable to noncontrolling interest		**(25,450)**	23,712	(21,750)
Other, net		**(1,087)**	10,576	11,827
Total	$	**(5,862)**	(293,741)	14,683

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2021 and 2020 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)		**2021**	2020
Deferred tax assets			
Property and leasehold costs	$	**241,833**	95,141
Liabilities for dismantlements		**37,728**	28,475
Postretirement and other employee benefits		**114,790**	128,281
U. S. net operating loss		**577,531**	589,067
Investment in partnership		**39,396**	65,216
Other deferred tax assets		**135,838**	112,685
Total gross deferred tax assets		**1,147,116**	1,018,865
Less valuation allowance		**(111,259)**	(106,448)
Net deferred tax assets		**1,035,857**	912,417
Deferred tax liabilities			
Deferred tax on undistributed foreign earnings		**(5,000)**	(5,000)
Accumulated depreciation, depletion and amortization		**(786,846)**	(665,255)
Other deferred tax liabilities		**(41,387)**	(27,250)
Total gross deferred tax liabilities		**(833,233)**	(697,505)
Net deferred tax (liabilities) assets	$	**202,624**	214,912

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 increased $4.8 million in 2021, related all to non-U.S. items. 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 $2.75 billion at year-end 2021 with a corresponding deferred tax asset of $577.5 million. The Company believes the U.S. net operating loss being carried forward will more likely than not be utilized in future periods prior to expirations in 2036 and 2037.

Other Information

Currently the Company considers $100 million of Canada's past foreign earnings not permanently reinvested, with an accompanying $5 million liability. At December 31, 2021, $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.

(Thousands of dollars)	**2021**	2020	2019
Balance at January 1	**$ 2,832**	2,538	2,903
Additions for tax positions related to current year	**71**	3,042	456
Settlements due to lapse of time	**—**	—	(821)
Settlements with taxing authorities	**—**	(2,748)	—
Balance at December 31	**$ 2,903**	2,832	2,538

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, 2021, 2020 and 2019 for interest and penalties of $0.3 million, $0.3 million and $0.1 million, respectively, associated with uncertain tax positions. Income tax expense for the years ended December 31, 2021, 2020 and 2019 included net benefits for interest and penalties of nil, $0.1 million and $0.1 million, respectively, associated with uncertain tax positions.

In 2022, the Company currently expects to add between $0.1 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 2022.

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. Additionally, the Company could be required to pay amounts into an escrow account as any matters are identified and appealed with the relevant taxing authorities. As of December 31, 2021, the earliest years remaining open for audit and/or settlement in the Company's major taxing jurisdictions are as follows: United States – 2016; Canada – 2016; and Malaysia – 2014. 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.

Coronavirus Aid, Relief, and Economic Security Act

In the fourth quarter of 2020, under the provisions of the Coronavirus Aid, Relief, and Economic Security (CARES) Act, the Company received a refund of its remaining outstanding AMT credit balance of approximately $18.5 million.

Note J – 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 settle in cash 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.

The Company currently has outstanding incentive awards issued to certain employees under the 2017 Annual Incentive Plan (2017 AIP), the 2012 Long-Term Incentive Plan (2012 Long-Term Plan), the 2018 Long-Term Incentive Plan (2018 Long-Term Plan) and the 2020 Long-Term Incentive Plan (2020 Long-Term Plan).

The 2017 AIP 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 2017 AIP expired on December 31, 2021 and has been replaced with the 2022 Annual Incentive Plan, effective January 1, 2022.

The 2020 Long-Term Plan authorizes the Committee to make grants of the Company's Common Stock to employees. These grants may be in the form of stock options (nonqualified or incentive), stock appreciation rights (SAR), restricted stock, restricted stock units (RSU), performance units, performance shares, dividend equivalents and other stock-based incentives. The 2020 Long-Term Plan expires in 2030. A total of 5 million shares are issuable during the life of the 2020 Long-Term Plan. Shares issued pursuant to awards granted under this Plan may be shares that are authorized and unissued or shares that were reacquired by the Company, including shares purchased in the open market. Share awards that have been canceled, expired, forfeited or otherwise not issued under an award shall not count as shares issued under this Plan. Based on awards made to date, 3.48 million shares are available for grant under the 2020 Long-Term Plan at December 31, 2021.

At the Company's annual stockholders' meeting held on May 12, 2021, shareholders approved the replacement of the 2018 Stock Plan for Non-Employee Directors (2018 NED Plan) with the 2021 Stock Plan for Non-Employee Directors (2021 NED Plan). The 2021 NED Plan 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 currently has outstanding incentive awards issued to Directors under the 2021 NED Plan and the 2018 NED Plan. All awards on or after May 12, 2021, were made under the 2021 NED Plan.

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)	**2021**	2020	2019
Compensation charged against income (loss) before income tax benefit	**$ 43,660**	24,812	50,170
Related income tax benefit recognized in income	**7,196**	2,672	7,389

As of December 31, 2021, there were $45.8 million in compensation costs to be expensed over approximately the next three 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, 2021, 2020 and 2019.

Equity-Settled Awards

PERFORMANCE-BASED RESTRICTED STOCK UNITS – Performance-based restricted stock units (PSUs) to be settled in Common shares were granted in 2021 under the 2020 Long-Term Plan and 2020 and 2019 under the

2018 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 (80% weighting), compared to an industry peer group of companies, and the EBITDA divided by Average Capital Employed (ACE) metric (20% weighting) for PSU awards beginning in 2020, over the performance period. 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.

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

(Number of stock units)	**2021**	2020	2019
Outstanding at beginning of year	**2,207,429**	2,129,733	1,660,417
Granted	**1,156,800**	999,700	957,600
Vested and issued	**(642,473)**	(429,194)	(331,917)
Forfeited	**(51,000)**	(492,810)	(156,367)
Outstanding at end of year	**2,670,756**	2,207,429	2,129,733

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 2021, 2020 and 2019 are presented in the following table.

	2021	2020	2019
Fair value per share at grant date	**$16.03**	$21.51	$28.09
Assumptions			
Expected volatility	**74.00%**	39.00%	46.00%
Risk-free interest rate	**0.18%**	1.40%	2.50%
Stock beta	**1.169**	0.864	1.037
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 2018 NED Plan and 2021 NED Plan and to certain employees under the 2012 Long-Term Plan, 2018 Long-Term Plan and 2020 Long-Term Plan.

The fair value of the time-based restricted stock units awarded in 2021, 2020 and 2019 are presented in the following table.

Type of Plan	**Valuation Methodology**	**2021**	2020	2019
Non-Employee Directors[1, 2]	Closing Stock Price at Grant Date	**$ 13.14 - 23.58**	$ 22.59	$ 21.68
Long-Term Incentive Plan[3]	Average High/Low Stock Price at Grant Date	**$ 12.30**	$ 21.68	$ 28.16

[1] Under the 2018 NED Plan, the RSUs granted in 2019 vest on the third anniversary of the date of grant and the RSUs granted in 2020 vest on the first anniversary of the date of grant.
[2] Under the 2021 NED Plan, RSUs granted in 2021 are scheduled to vest in February 2022.
[3] The RSUs granted under the 2012 Plan will vest on the fifth anniversary of the date of grant. The RSUs granted under the 2018 and 2020 Long-Term Plan generally vest on the third anniversary of the date of grant.

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

(Number of share units)	**2021**	2020	2019
Outstanding at beginning of year	**1,383,043**	1,535,080	1,538,854
Granted	**573,907**	446,848	409,692
Vested and issued	**(476,012)**	(271,285)	(275,738)
Forfeited	**(29,500)**	(327,600)	(137,728)
Outstanding at end of year	**1,451,438**	1,383,043	1,535,080

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.

Prior to 2018, 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 was 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.

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, 2018	3,994,595	$ 44.66
Exercised	(57,500)	17.57
Forfeited	(1,016,685)	48.29
Outstanding at December 31, 2019	2,920,410	43.93
Exercised	(47,000)	17.57
Forfeited	(825,010)	54.85
Outstanding at December 31, 2020	2,048,400	40.14
Exercised	**(170,000)**	**17.57**
Forfeited	**(558,900)**	**52.61**
Outstanding at December 31, 2021	**1,319,500**	**37.77**
Exercisable at December 31, 2018	3,182,345	$ 49.10
Exercisable at December 31, 2019	2,694,410	43.51
Exercisable at December 31, 2020	2,048,400	37.88
Exercisable at December 31, 2021	**1,319,500**	**34.25**

Additional information about stock options outstanding at December 31, 2021 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	773,500	1.6	$ 3,097,563	773,500	1.6	$ 3,097,563
$31.00 to $50.99	546,000	0.1	—	546,000	0.1	—
	1,319,500	1.0	**$ 3,097,563**	**1,319,500**	1.0	**$ 3,097,563**

The total intrinsic value of options exercised during 2021 was $1.2 million. 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.

Cash-Settled Awards

The Company has granted phantom 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 pre-tax expense recorded in the Consolidated Statements of Operations for all cash-settled stock-based awards was $18.2 million in 2021, $1.5 million in 2020 and $16.9 million in 2019.

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 $29.0 million, $9.8 million and $34.1 million was recorded in 2021, 2020 and 2019, respectively, for these plans.

Note K – 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 other postretirement benefits such as 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.

In 2020, the Company announced that it was closing its headquarters office in El Dorado, Arkansas, its office in Calgary, Alberta, and consolidating all worldwide staff activities to its existing office location in Houston, Texas. As a result of this decision and the subsequent restructuring activities, a pension remeasurement was triggered and the Company incurred pension curtailment and special termination benefit charges as a result of the associated reduction in force in 2020.

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, 2021 and 2020 and a statement of the funded status as of December 31, 2021 and 2020.

(Thousands of dollars)	Pension Benefits 2021	Pension Benefits 2020	Other Postretirement Benefits 2021	Other Postretirement Benefits 2020
Change in benefit obligation				
Obligation at January 1	$ **981,467**	883,269	**108,378**	108,401
Service cost	**8,199**	7,967	**1,295**	1,373
Interest cost	**14,784**	21,127	**2,071**	2,626
Participant contributions	**—**	—	**2,648**	2,225
Actuarial loss (gain)	**(24,440)**	107,258	**(9,519)**	3,758
Medicare Part D subsidy	**—**	—	**300**	243
Exchange rate changes	**(1,764)**	7,074	**3**	13
Benefits paid	**(38,866)**	(46,066)	**(4,041)**	(4,238)
Curtailments	**—**	(7,596)	**—**	(6,023)
Special termination benefits	**—**	8,434	**—**	—
Plan amendments	**—**	—	**(5,002)**	—
Obligation at December 31	**939,380**	981,467	**96,133**	108,378
Change in plan assets				
Fair value of plan assets at January 1	**586,720**	547,484	**—**	—
Actual return on plan assets	**33,687**	48,115	**—**	—
Employer contributions	**31,607**	30,178	**1,093**	1,770
Participant contributions	**—**	—	**2,648**	2,225
Medicare Part D subsidy	**—**	—	**300**	243
Exchange rate changes	**(1,846)**	7,009	**—**	—
Benefits paid	**(38,866)**	(46,066)	**(4,041)**	(4,238)
Fair value of plan assets at December 31	**611,302**	586,720	**—**	—
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	**5,535**	4,572	**—**	—
Other accrued liabilities	**(10,144)**	(9,468)	**(4,867)**	(5,298)
Deferred credits and other liabilities	**(323,469)**	(389,851)	**(91,266)**	(103,080)
Fund Status and net plan liability recognized at December 31	$ **(328,078)**	(394,747)	**(96,133)**	(108,378)

At December 31, 2021, 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)	$ (280,462)	13,233
Prior service cost	(2,920)	5,002
	$ (283,382)	18,235

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)	**2021**	2020	**2021**	2020	**2021**	2020
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	$ **734,375**	762,134	**723,887**	753,475	**589,529**	564,238
Unfunded nonqualified and directors' plans where accumulated benefit obligation exceeds fair value of plan assets	**188,713**	201,372	**188,530**	198,792	**—**	—
Unfunded other postretirement plans	**96,133**	108,378	**96,133**	108,378	**—**	—

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2021.

	Pension Benefits			Other Postretirement Benefits		
(Thousands of dollars)	**2021**	2020	2019	**2021**	2020	2019
Service cost	$ **8,199**	7,967	7,964	**1,295**	1,373	1,559
Interest cost	**14,784**	21,127	27,835	**2,071**	2,626	3,864
Expected return on plan assets	**(19,222)**	(24,316)	(25,719)	**—**	—	—
Amortization of prior service cost (credit)	**591**	640	964	**—**	—	—
Recognized actuarial (gain) loss	**20,565**	22,828	14,106	**(29)**	(31)	(193)
Net periodic benefit expense	**24,917**	28,246	25,150	**3,337**	3,968	5,230
Termination benefits expense	**—**	8,434	—	**—**	—	—
Curtailment expense	**—**	586	—	**—**	(1,825)	—
Total net periodic benefit expense	$ **24,917**	37,266	25,150	**3,337**	2,143	5,230

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

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2021**	2020	**2021**	2020
Benefit obligation at December 31	$ **225,117**	230,101	**526**	492
Fair value of plan assets at December 31	**218,746**	221,463	**—**	—
Net plan liabilities recognized	**(6,371)**	(8,638)	**(526)**	(492)
Net periodic benefit expense (benefit)	**598**	437	**64**	46

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2021 and 2020 and net periodic benefit expense for 2021 and 2020.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,		Year		Year	
	2021	2020	**2021**	2020	**2021**	2020	**2021**	2020
Discount rate	**2.54 %**	2.25 %	**2.86 %**	2.50 %	**2.24 %**	2.75 %	**2.51 %**	3.16 %
Expected return on plan assets	**4.25 %**	4.43 %	**—**	—	**4.25 %**	4.43 %	**—**	—
Rate of compensation increase	**3.04 %**	3.04 %	**—**	—	**3.04 %**	3.28 %	**—**	—

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
2022	$ 45,619	4,867
2023	45,714	4,886
2024	46,581	4,876
2025	46,259	4,835
2026	46,830	4,843
2027-2031	240,308	24,295

For purposes of measuring postretirement benefit obligations at December 31, 2021, the future annual rates of increase in the cost of health care were assumed to be 5.9% for 2021 decreasing each year to an ultimate rate of 3.8% in 2038 and thereafter.

During 2021, the Company made contributions of $31.2 million to its domestic defined benefit pension plans and $1.1 million to its domestic postretirement benefits plan. During 2022, the Company currently expects to make contributions of $35.0 million to its domestic defined benefit pension plans, $3.2 million to its foreign defined benefit pension plans and $4.9 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. Our investment strategy is to maximize long-term returns at an acceptable level of risk through broad diversification of plan assets in a variety of asset classes. Asset classes and target allocations are determined by our investment committee and include equities, fixed income and other investments, including hedge funds, real estate and cash equivalent securities. Investment managers are prohibited from investing in equity or fixed income securities issues by the Company. The majority of plan assets are highly liquid, providing flexibility for benefit payment requirements. The current target allocations for plan assets are 40-70% equity securities, 30-60% fixed income securities, 0-15% alternatives and 0-15% cash and equivalents. Asset allocations are rebalanced on a periodic basis throughout the year to bring assets to within an acceptable range of target levels.

The weighted average asset allocation for the Company's funded pension benefit plans at December 31, 2021 and 2020 are presented in the following table.

	December 31,	
	2021	2020
Equity securities	**60.9 %**	58.1 %
Fixed income securities	**21.7**	24.0
Alternatives	**13.5**	13.2
Cash equivalents	**3.9**	4.7
	100.0 %	100.0 %

The Company's weighted average expected return on plan assets was 4.0% in 2021, 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 4.0% expected return was based on a weighted average expected future equity securities return of 3.4% and a fixed income securities return of 0.6%. There is also an average expected investment expense of 0.5%. Over the last 10 years, the return on funded retirement plan assets has averaged 8.2%.

At December 31, 2021, 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, 2021**	**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	**$ 108,422**	**108,422**	**—**	**—**
U.S. small/midcap	**73,222**	**73,222**	**—**	**—**
Other alternative strategies	**47,248**	**—**	**—**	**47,248**
International equity	**47,546**	**47,546**	**—**	**—**
Emerging market equity	**14,937**	**14,937**	**—**	**—**
Fixed income securities:				
U.S. fixed income	**92,231**	**36,888**	**55,343**	**—**
Cash and equivalents	**8,951**	**8,951**	**—**	**—**
Total Domestic Plans	**392,557**	**289,966**	**55,343**	**47,248**
Foreign Plans				
Equity securities funds	**73,642**	**—**	**73,642**	**—**
Fixed income securities funds	**40,610**	**—**	**40,610**	**—**
Diversified pooled fund	**54,317**	**—**	**54,317**	**—**
Other	**35,606**	**—**	**—**	**35,606**
Cash and equivalents	**14,570**	**—**	**14,570**	**—**
Total Foreign Plans	**218,745**	**—**	**183,139**	**35,606**
Total	**$ 611,302**	**289,966**	**238,482**	**82,854**

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

At December 31, 2020, 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, 2020	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	$ 67,326	67,326	—	—
U.S. small/midcap	28,953	28,953	—	—
Hedged funds and other alternative strategies	42,040	—	—	42,040
International commingled trust fund	76,095	987	55,433	19,675
Emerging market commingled equity fund	32,058	10,480	21,578	—
Fixed income securities:				
U.S. fixed income	92,668	—	92,668	—
International commingled trust fund	9,456	—	9,456	—
Cash and equivalents	16,661	16,661	—	—
Total Domestic Plans	365,257	124,407	179,135	61,715
Foreign Plans				
Equity securities funds	74,393	—	74,393	—
Fixed income securities funds	45,240	—	45,240	—
Diversified pooled fund	54,871	—	54,871	—
Other	35,970	—	—	35,970
Cash and equivalents	10,989	—	10,989	—
Total Foreign Plans	221,463	—	185,493	35,970
Total	$ 586,720	124,407	364,628	97,685

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

For domestic plans, U.S. core, small/midcap, international, emerging market equity securities and U.S. treasury securities are quoted prices in active markets. For commercial paper securities, the prices received generally utilize observable inputs in the pricing methodologies. Other alternative strategies funds consist of three investments. One of these investments is valued quarterly based on net asset value and permits withdrawals after a 45-day notice, another investment is valued annually based on net asset value and permits withdrawals semi-annually after a 90-day notice, and the third investment is also valued quarterly based on net asset values and has a two-year lock-up period and a 95-day notice following the lock-up period.

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. and Canadian securities valued daily at net asset values. The diversified pooled fund is valued daily at net asset value and contains a combination of U.K. and foreign equity securities.

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, 2019	$ 111,586
Actual return on plan assets:	
Relating to assets held at the reporting date	5,694
Purchases, sales and settlements	(19,595)
Total at December 31, 2020	97,685
Actual return on plan assets:	
Relating to assets held at the reporting date	**5,206**
Purchases, sales and settlements	**(20,037)**
Total at December 31, 2021	**$ 82,854**

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 $5.4 million in 2021, $6.6 million in 2020 and $8.4 million in 2019.

Note L – Financial Instruments and Risk Management

DERIVATIVE INSTRUMENTS – Murphy uses derivative instruments, such as swaps and zero-cost commodity price collar contracts, 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 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 previously 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 time. In 2021, the Company redeemed all of the remaining notes due 2022, which were associated with the interest rate derivative contracts, and expensed the remainder of the previously deferred loss on the interest rate swap of $2.1 million to Interest expense in the Consolidated Statement of Operations.

Commodity Price Risks

The Company has entered into crude oil swaps and collar contracts. Under the swaps contracts, which mature monthly, the Company pays the average monthly price in effect and receives the fixed contract price on a notional amount of sales volume, thereby fixing the price for the commodity sold. Under the collar contracts, which also mature monthly, the Company purchased a put option and sold a call option with no net premiums paid to or received from counterparties. Upon maturity, collar contracts require payments by the Company if the NYMEX average closing price is above the ceiling price or payments to the Company if the NYMEX average closing price is below the floor price.

At December 31, 2021, volumes per day associated with outstanding crude oil derivative contracts and the weighted average prices for these contracts are as follows:

		2022
NYMEX WTI swap contracts:		
Volume per day (Bbl):		**20,000**
Price per Bbl:	**$**	**44.88**
NYMEX WTI collar contracts:		
Volume per day (Bbl):		**25,000**
Price per Bbl:		
Average Ceiling:	**$**	**75.20**
Average Floor:		**63.24**

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, 2021 and 2020.

At December 31, 2021 and 2020, the fair value of derivative instruments not designated as hedging instruments are presented in the following table. See also Note P.

(Thousands of dollars)	**Asset (Liability) Derivatives Fair Value at December 31,**		
Type of Derivative Contract	**Balance Sheet Location**	**2021**	2020
Commodity swaps	**Accounts receivable**	**$ —**	13,050
	Accounts payable	**(239,882)**	(89,842)
	Deferred credits and other liabilities	**—**	(12,833)
Commodity collars	**Accounts receivable**	**4,280**	—
	Accounts payable	**(19,533)**	—

For the years ended December 31, 2021, 2020, and 2019, 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**	**2021**	2020	2019
Commodity swaps	**(Loss) gain on derivative instruments**	**$ (510,596)**	202,661	(856)
Commodity collars	**(Loss) gain on derivative instruments**	**(15,254)**	—	—

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. and Canada, and cost sharing amounts of operating and capital costs billed to partners for properties 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 to any one customer. Cash balances and cash equivalents are held with several major financial institutions, which limit the Company's exposure to credit risk for its cash assets. 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 M – 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, 2021. The following table reconciles the weighted-average shares outstanding used for these computations.

(Weighted-average shares)	**2021**	2020	2019
Basic method	**154,290,741**	153,507,109	163,992,427
Dilutive stock options [1]	**—**	—	820,001
Diluted method	**154,290,741**	153,507,109	164,812,428

[1] Due to a net loss recognized by the Company for the year ended December 31, 2021 and 2020, 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, 2021 but were not included in the computation of dilutive earnings per share because the incremental shares from the assumed conversion were antidilutive.

	2021	2020	2019
Antidilutive stock options excluded from diluted shares	**1,420,992**	2,246,532	2,947,401
Weighted average price of these options	**$35.30**	$39.67	$45.26

Note N – 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 $1.0 million in 2021, $(0.9) million in 2020 and $(6.0) million in 2019.

Noncash operating working capital (increased) decreased during each of the three years ended December 31, 2021 as shown in the following table.

(Thousands of dollars)		**2021**	2020	2019
Net decrease (increase) in operating working capital, excluding cash and cash equivalents:				
Decrease (increase) in accounts receivable [1]	**$**	**8,056**	164,613	(232,037)
Decrease in inventories		**12,809**	5,953	10,258
Decrease in prepaid expenses		**2,003**	7,178	4,650
Increase (decrease) in accounts payable and accrued liabilities [1]		**95,166**	(208,740)	196,773
Increase (decrease) in income taxes payable		**423**	(1,031)	3,469
Net decrease (increase) in noncash operating working capital	**$**	**118,457**	(32,027)	(16,887)
Supplementary disclosures:				
Cash income taxes paid, net of refunds	**$**	**2,138**	(44,175)	(6,645)
Interest paid, net of amounts capitalized of $16.1 million in 2021, $8.0 million in 2020 and $1.8 million in 2019		**165,699**	191,561	179,722
Non-cash investing activities:				
Asset retirement costs capitalized	**$**	**54,439**	14,736	33,874
(Increase) decrease in capital expenditure accrual		**9,788**	84,645	(73,426)

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

Note O – Accumulated Other Comprehensive Loss

The components of Accumulated other comprehensive loss on the Consolidated Balance Sheets at December 31, 2021 and December 31, 2020 and the changes during 2021 and 2020 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, 2019	(353,252)	(218,015)	(2,894)	(574,161)
2020 components of other comprehensive income (loss):				
Before reclassifications to income	29,241	(70,815)	—	(41,574)
Reclassifications to income	—	13,198 [1]	1,204 [2]	14,402
Net other comprehensive income	29,241	(57,617)	1,204	(27,172)
Balance at December 31, 2020	(324,011)	(275,632)	(1,690)	(601,333)
2021 components of other comprehensive income (loss):				
Before reclassifications to income	**12,116**	**40,095**	**—**	**52,211**
Reclassifications to income	**—**	**19,721** [1]	**1,690** [2]	**21,411**
Net other comprehensive income (loss)	**12,116**	**59,816**	**1,690**	**73,622**
Balance at December 31, 2021	**$ (311,895)**	**(215,816)**	**—**	**(527,711)**

[1] Reclassifications before taxes of $23,503 and $17,694 are included in the computation of net periodic benefit expense in 2021 and 2020, respectively. See Note K for additional information. Related income taxes of $3,782 and $4,496 are included in income tax expense in 2021 and 2020, respectively.
[2] Reclassifications before taxes of $2,140 and $1,525 are included in Interest expense in 2021 and 2020, respectively. Related income taxes of $450 and $321 are included in income tax expense in 2021 and 2020, respectively. See Note L for additional information.

Note P – Assets and Liabilities Measured at Fair Value

Fair Values – Recurring

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

The fair value measurements for these assets and liabilities at December 31, 2021 and 2020 are presented in the following table.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued
Note P – Assets and Liabilities Measured at Fair Value (Contd.)

(Thousands of dollars)	**December 31, 2021**				December 31, 2020			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:								
Commodity collars	**$ —**	**4,280**	**—**	**4,280**	—	—	—	—
Commodity swaps	**—**	**—**	**—**	**—**	—	13,050	—	13,050
	$ —	**4,280**	**—**	**4,280**	—	13,050	—	13,050
Liabilities:								
Nonqualified employee savings plan	**$ 16,962**	**—**	**—**	**16,962**	14,988	—	—	14,988
Commodity collars	**—**	**19,533**	**—**	**19,533**	—	—	—	—
Contingent consideration	**—**	**—**	**196,151**	**196,151**	—	—	133,004	133,004
Commodity swaps	**—**	**239,882**	**—**	**239,882**	—	102,675	—	102,675
	$ 16,962	**259,415**	**196,151**	**472,528**	14,988	102,675	133,004	250,667

The fair value of the commodity (WTI crude oil) swaps in 2021 and 2020 was based on active market quotes for WTI crude oil. The fair value of commodity (WTI crude oil) collars in 2021 was determined using an option pricing model based on inputs that include (i) the contracted notional volumes, (ii) independent active market price quotes, (iii) the applicable estimated risk-free rate yield curve and (iv) the implied rate of volatility inherent in the collar contract. The before tax income effect of changes in fair value of crude oil derivative contracts is recorded in Gain (loss) on derivative instruments in the Consolidated Statements of Operations.

The nonqualified employee savings plan is an unfunded savings plan through which participants seek a return via phantom investments in equity securities and/or mutual funds. The fair value of this liability was based on quoted prices for these equity securities and mutual funds. The income effect of changes in the fair value of the nonqualified employee savings plan is recorded in Selling and general expenses in the Consolidated Statements of Operations.

The Company’s contingent consideration liabilities with PAI and LLOG 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, 2021: (i) the remaining expected life of 1 year for LLOG and 4 years for PAI, (ii) West Texas Intermediate forward strip pricing with historical volatility of 9.9%, and (iii) a risk-free interest rate of 1.49%. 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, 2021 and 2020.

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2021 and 2020. 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,			
	2021		2020	
(Thousands of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial assets (liabilities):				
Current and long-term debt	**$ (2,466,068)**	**(2,666,773)**	(2,988,067)	(2,948,171)

Fair Values – Nonrecurring

An impairment charge of $171.3 million was triggered when the operator at Terra Nova provided notice of abandonment in the first quarter of 2021, before a commercial resolution in the third quarter of 2021 led Murphy to acquire an additional 7.525% in a commercial settlement with the other partners. The commercial resolution would have meant the Terra Nova impairment charge was not required. In the fourth quarter of 2021, a further impairment charge of $25.0 million was recorded on non-core assets.

In 2020, declines in future oil and natural gas prices (principally driven by reduced demand in response to the COVID-19 pandemic and increased supply in the first quarter of 2020 from foreign oil producers) led to impairments in certain of the Company's U.S. Offshore and Other Foreign properties. The Company recorded pretax noncash impairment charges of $1,206.3 million to reduce the carrying values to their estimated fair values at select properties.

The fair values were determined by internal discounted cash flow models using estimates of future production, prices, costs and discount rates 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

	Years Ended December 31,					
	Fair Value				Net Book Value Prior to Impairment	Total Pretax Impairment
(*Thousands of dollars*)		Level 1	Level 2	Level 3		
2021						
Assets:						
Impaired proved properties						
CA Offshore	**$**	**—**	**—**	**156,185**	**327,481**	**171,296**
Other Foreign		**—**	**—**	**25,739**	**43,739**	**18,000**
Corporate		**—**	**—**	**36,994**	**43,994**	**7,000**
2020						
Assets:						
Impaired proved properties						
U.S. Offshore	$	—	—	2,618,001	3,770,516	1,152,515
Other Foreign		—	—	42,980	82,689	39,709
Corporate		—	—	58,199	72,259	14,060

Note Q – 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 2045, while the Western Canada processing contracts call for minimum monthly payments through 2051. In the U.S. and Western Canada, future required minimum annual payments for the next five years are $221.4 million in 2022, $168.1 million in 2023, $114.4 million in 2024, $89.8 million in 2025 and $82.4 million in 2026. 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 $151.8 million in 2021, $107.6 million in 2020, and $117.7 million in 2019.

Commitments for capital expenditures were approximately $520.1 million at December 31, 2021, including $392.4 million for costs to develop deepwater U.S. Gulf of Mexico fields including fields acquired as part of the MP GOM and LLOG transactions, $84.7 million for Canada, $24.9 million for Other Foreign, and $18.1 million for work at Eagle Ford Shale.

Note R – Environmental and Other Contingencies

The Company's operations and earnings have been and may be affected by various forms of governmental action both in the United States and throughout the world. Examples of such governmental action include, but are by no means limited to: tax legislation changes, including tax rate changes, and retroactive tax claims; royalty and revenue sharing 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. Item 103 of SEC Regulation S-K requires disclosure of certain environmental matters when a governmental authority is a party to the proceedings and such proceedings involve potential monetary sanctions that the Company reasonably believes will exceed a specified threshold. Pursuant to recent SEC amendments to this item, the Company will be using a threshold of $1.0 million for such proceedings.

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. 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 investigate, remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to investigate and 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 additional expenditures could be required at known sites. However, based on information currently available to the Company, the amount of future investigation and 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 S – Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2021 is shown below.

(*Number of shares outstanding*)	**2021**	2020	2019
Beginning of year	**153,598,625**	152,935,361	173,058,829
Stock options exercised [1]	**32,554**	11,359	12,345
Restricted stock awards [1]	**831,871**	651,905	561,729
Treasury shares purchased	**—**	—	(20,697,542)
End of year	**154,463,050**	153,598,625	152,935,361

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

Note T – 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 the years 2021, 2020 and 2019, sales to Chevron represented approximately 30%, 24%, and 25% of the Company's total sales revenue. During the years 2020 and 2019, sales to Phillips 66 represented approximately 18%, and 17% 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.

Assets held for sale as of December 31, 2021 include the net property, plant and equipment of the CA-2 project in Brunei and the Company's office building in El Dorado, Arkansas (see Note 2). The U.K. and Malaysian operations have been reported as Discontinued operations for all periods presented in these consolidated financial statements. The Company completed the sale of its Malaysian assets in 2019.

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 T - Business Segments (Contd.)

	Exploration and Production						
(Millions of dollars)	United States [1]	Canada	Other	Total E&P	Corporate and Other	Discontinued Operations	Consolidated Total
Year ended December 31, 2021							
Segment income (loss) - including NCI [1]	**$ 766.3**	**(16.1)**	**(33.5)**	**716.7**	**$ (668.0)**	**(1.2)**	**47.5**
Revenues from external customers	**2,337.5**	**476.3**	**4.9**	**2,818.7**	**(519.4)**	**—**	**2,299.3**
Interest and other income (loss)	**(11.6)**	**(1.9)**	**3.2**	**(10.3)**	**(6.5)**	**—**	**(16.8)**
Interest expense, net of capitalization	**—**	**—**	**(0.2)**	**(0.2)**	**(221.6)**	**—**	**(221.8)**
Income tax expense (benefit)	**183.9**	**(1.7)**	**(9.5)**	**172.7**	**(178.6)**	**—**	**(5.9)**
Significant noncash charges (credits)							
Impairment of assets	**—**	**171.3**	**18.0**	**189.3**	**7.0**	**—**	**196.3**
Depreciation, depletion and amortization	**616.5**	**163.8**	**1.8**	**782.1**	**13.0**	**—**	**795.1**
Accretion of asset retirement obligations	**36.9**	**9.7**	**—**	**46.6**	**—**	**—**	**46.6**
Amortization of undeveloped leases	**11.1**	**0.2**	**7.6**	**18.9**	**—**	**—**	**18.9**
Deferred and noncurrent income taxes	**176.3**	**(1.9)**	**(8.0)**	**166.4**	**(170.5)**	**—**	**(4.1)**
Additions to property, plant, equipment	**519.5**	**52.7**	**13.1**	**585.3**	**—**	**—**	**585.3**
Total assets at year-end	**6,591.6**	**2,231.9**	**259.8**	**9,083.3**	**1,220.8**	**0.8**	**10,304.9**
Year ended December 31, 2020							
Segment income (loss) - including NCI [1]	$ (1,014.3)	(35.0)	(85.6)	(1,134.9)	$ (120.3)	(7.2)	(1,262.4)
Revenues from external customers	1,411.8	345.8	1.8	1,759.4	207.9	—	1,967.3
Interest and other income (loss)	(9.9)	0.8	0.8	(8.2)	(9.1)	—	(17.3)
Interest expense, net of capitalization	—	(0.5)	(0.4)	(0.9)	(168.5)	—	(169.4)
Income tax expense (benefit)	(244.2)	(21.4)	2.1	(263.5)	(30.2)	—	(293.7)
Significant noncash charges (credits)							
Impairment of assets	1,152.5	—	39.7	1,192.2	14.1	—	1,206.3
Depreciation, depletion and amortization	749.4	213.2	2.3	964.9	22.3	—	987.2
Accretion of asset retirement obligations	36.6	5.5	—	42.1	—	—	42.1
Amortization of undeveloped leases	17.2	0.4	9.1	26.7	—	—	26.7
Deferred and noncurrent income taxes	(244.2)	(10.6)	1.9	(252.9)	(25.1)	—	(278.0)
Additions to property, plant, equipment	623.1	118.3	15.2	756.6	—	—	756.6
Total assets at year-end	6,915.5	2,404.1	267.7	9,587.3	1,032.9	0.7	10,620.9

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

(Millions of dollars)	Exploration and Production: United States [1]	Exploration and Production: Canada	Exploration and Production: Other	Exploration and Production: Total E&P	Corporate and Other	Discontinued Operations	Consolidated Total
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

[1] Includes results attributable to a noncontrolling interest in MP GOM.

Geographic Information (Millions of dollars)	Certain Long-Lived Assets at December 31: United States	Canada	Other	**Total**
2021	**$ 6,371.4**	**1,566.9**	**189.6**	**8,127.9**
2020	6,395.7	1,702.5	170.8	8,269.0
2019	8,003.9	1,761.2	204.6	9,969.7

Note U – 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 19 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:

		Year Ended December 31,	
(Thousands of dollars)	**Financial Statement Category**	**2021**	**2020**
Operating lease [1,2]	Lease operating expenses	**$ 198,189**	$ 208,104
Operating lease [2]	Transportation, gathering and processing	**39,396**	39,121
Operating lease [2]	Selling and general expense	**9,019**	10,638
Operating lease [2]	Other operating expense	**7,480**	9,524
Operating lease [2]	Exploration Expenses	**902**	994
Operating lease	Impairment of assets	**—**	6,565
Operating lease [2]	Property, plant and equipment	**81,924**	40,227
Operating lease [2]	Asset retirement obligations	**11,103**	—
Finance lease			
Amortization of asset	Depreciation, depletion and amortization	**1,173**	—
Interest on lease liabilities	Interest expense, net	**228**	372
Sublease income	Other income	**(2,482)**	(1,118)
Net lease expense		**$ 346,932**	$ 314,427

[1] *Variable lease expenses.* For the year ended December 31, 2021 and 2020, includes variable lease expenses of $25.8 million and $21.8 million, primarily related to additional volumes processed at a natural gas processing plant.

[2] *Short-term leases due within 12 months.* For the year ended December 31, 2021, includes $56.9 million in Lease operating expense, $30.2 million for Transportation, gathering and processing, $2.1 million in Selling and general expense, $0.2 million in Other operating expense, $28.9 million in Property, plant and equipment, net and $11.1 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.

For the year ended December 31, 2020, includes $73.9 million in Lease operating expense, $22.9 million in Transportation, gathering, and processing, $3.3 million in Selling general expense, $2.5 million in Other operating expense, and $25.0 million in Property, plant and equipment, net relating to short-term leases due within 12 months. Expenses primarily relate to drilling rigs and other oil and natural gas field equipment.

Maturity of Lease Liabilities

(Thousands of dollars)	**Operating Leases**	**Finance Leases**	**Total**
2022	$ 184,854	1,068	185,922
2023	137,767	1,069	138,836
2024	132,568	1,069	133,637
2025	82,063	1,069	83,132
2026	64,660	1,069	65,729
Remaining	648,805	2,404	651,209
Total future minimum lease payments	1,250,717	7,748	1,258,465
Less imputed interest	(350,128)	(2,259)	(352,387)
Present value of lease liabilities [1]	**$ 900,589**	**5,489**	**906,078**

[1] Includes both the current and long-term portion of the lease liabilities.

Lease Term and Discount Rate

	December 31, 2021	December 31, 2020
Weighted average remaining lease term:		
Operating leases	**12 years**	12 years
Finance leases	**7 years**	8 years
Weighted average discount rate:		
Operating leases	**5.7 %**	5.8 %
Finance leases	**4.7 %**	4.7 %

Other Information

	Year Ended December 31,	
(Thousands of dollars)	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	**$ 194,412**	$ 160,385
Operating cash flows from finance leases	**228**	372
Financing cash flows from finance leases	**803**	695
Right-of-use assets obtained in exchange for lease liabilities:		
Operating leases [1]	**$ 95,500**	$ 453,719

[1] For the year ended December 31, 2021, includes $90.3 million related to an offshore drilling rig with a lease term of 16 months. December 31, 2020, includes $268.8 million related to a 5-year lease for the Cascade/Chinook FPSO in the U.S. Gulf of Mexico and $168.4 million related to a 20-year lease for a gas plant expansion in Canada.

Note V – Restructuring Charges

In 2020, the Company announced that it was closing its headquarters office in El Dorado, Arkansas, its office in Calgary, Alberta, and consolidating all worldwide staff activities to its existing office location in Houston, Texas. As a result of this decision, certain directly attributable costs and charges have been recognized and reported as Restructuring charges as part of net loss during the year ended December 31, 2020. These costs include severance, relocation, IT costs, pension curtailment charges and a write-off of the right of use asset lease associated with the Canada office. Further, the office building in El Dorado is classified as held for sale as of December 31, 2020 and 2021. Restructuring charges are primarily reported in the Corporate segment.

The following table presents a summary of the restructuring charges included in Operating (loss) income from continuing operations for the year ended December 31, 2020:

(Thousands of dollars)	Year Ended December 31, 2020
Severance	$ 25,088
Contract exit costs and other	13,993
Pension and termination benefit charges	10,913
Restructuring charges	$ 49,994

The following table represents a reconciliation of the liability associated with the Company's restructuring activities at December 31, 2020 and 2021, which is reflected in Other accrued liabilities on the Consolidated Balance Sheet:

(Thousands of dollars)	
Restructuring accruals	$ 32,430
2020 Utilizations	(25,500)
Liability at December 31, 2020	6,930
2021 Utilizations	**(4,757)**
Liability at December 31, 2021	**$ 2,173**

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 2021 were $66.56 per barrel for NYMEX crude oil (WTI), and $3.60 per Mcf for natural gas (Henry Hub). The average prices used for 2020 were $39.57 per barrel for NYMEX crude oil (WTI), and $1.98 per Mcf for natural gas (Henry Hub). 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). 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. Estimates are presented in millions of barrels of oil equivalents and dollars and billions of cubic feet with one decimal; totals within the tables may not add as a result of rounding. 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.

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, 2021.

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

Schedule 1 – Summary of Total Proved Equivalent Reserves Based on Average Prices for 2018 – 2021

	Equivalents			
(Millions of barrels of oil equivalent)	Total	United States	Canada	Malaysia and Other
Proved developed and undeveloped reserves:				
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	825.0	500.1	324.1	0.8
Revisions of previous estimates	(194.7)	(146.6)	(47.3)	(0.8)
Extensions and discoveries	150.3	19.5	130.7	—
Sales of properties	(1.7)	(1.7)	—	—
Production	(63.9)	(42.8)	(21.1)	—
December 31, 2020	714.9	328.5	386.4	—
Revisions of previous estimates	**(52.9)**	**35.6**	**(89.3)**	**0.8**
Extensions and discoveries	**109.4**	**18.2**	**91.3**	**—**
Purchases of properties	**7.4**	**1.6**	**5.8**	**—**
Sales of properties	**(0.7)**	**—**	**(0.7)**	**—**
Production	**(61.1)**	**(40.4)**	**(20.6)**	**(0.1)**
December 31, 2021 [1]	**716.9**	**343.4**	**372.8**	**0.7**
Proved developed reserves:				
December 31, 2018	430.2	247.0	124.2	59.1
December 31, 2019	472.3	273.4	198.1	0.8
December 31, 2020	410.8	230.3	180.5	—
December 31, 2021 [2]	**419.2**	**241.9**	**176.8**	**0.6**
Proved undeveloped reserves:				
December 31, 2018	413.8	178.7	164.5	70.7
December 31, 2019	352.7	226.7	126.0	—
December 31, 2020	304.1	98.2	205.9	—
December 31, 2021 [3]	**297.7**	**101.6**	**196.0**	**0.1**

[1] Includes proved reserves of 18.4 MMBOE, consisting of 16.6 MMBBL oil, 0.7 MMBBL NGLs, and 6.1 BCF natural gas attributable to the noncontrolling interest in MP GOM.

[2] Includes proved developed reserves of 16.2 MMBOE, consisting of 14.6 MMBBL oil, 0.6 MMBBL NGLs, and 5.4 BCF natural gas attributable to the noncontrolling interest in MP GOM.

[3] Includes proved undeveloped reserves of 2.2 MMBOE, consisting of 2.0 MMBBL oil, 0.1 MMBBL NGLs, and 0.7 BCF natural gas attributable to the noncontrolling interest in MP GOM.

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

Schedule 1 – Summary of Total Proved Equivalent Reserves Based on Average Prices for 2018 – 2021 – Continued

2021 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The equivalent reserves revisions in 2021 resulted predominantly from accelerated royalty incentive payouts due to higher commodity prices in Tupper Montney. These negative revisions were partially offset by positive revisions in the U.S. from higher commodity prices, which partially reversed the 2020 capital allocation reduction, and improved well performance in the U.S. Gulf of Mexico.

Extensions and discoveries - In 2021, proved equivalent reserves were added for drilling and expansion activities predominantly in Canada at Tupper Montney as well as in the U.S. at the Eagle Ford Shale and the Gulf of Mexico.

Purchases and sales of properties - In 2021, the Company acquired incremental working interest in Terra Nova offshore Canada and in the U.S. Gulf of Mexico.

2020 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The negative reserves revisions in 2020 resulted predominantly from lower crude oil prices and lower capital allocation to Onshore shale properties over the next 5 years causing the removal of numerous proved undeveloped locations, partially offset by improved well performance in the Gulf of Mexico. The 2020 negative equivalents revision in the U.S. was primarily attributable to lower capital allocation in the Eagle Ford Shale, and the negative revision in Canada was primarily attributable to the Kaybob Duvernay. Lower commodity prices also resulted in negative equivalents revisions in the U.S offshore and Canada offshore.

Extensions and discoveries - In 2020, proved equivalent reserves were added for drilling and expansion activities predominantly in Canada at Tupper Montney as well as in the U.S. at the Eagle Ford Shale. Proved equivalent reserves were also added for drilling activities in both the U.S. offshore and Canada offshore.

Purchases and sales of properties - In 2020, the Company divested partial working interest in an undeveloped well in the Gulf of Mexico.

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.

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

Schedule 2 – Summary of Proved Crude Oil Reserves Based on Average Prices for 2018 – 2021

(Millions of barrels)	Total	United States	Canada	Malaysia and Other
Proved developed and undeveloped crude oil reserves:				
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	423.9	377.8	45.3	0.8
Revisions of previous estimates	(137.4)	(116.8)	(19.8)	(0.8)
Extensions and discoveries	19.6	14.5	5.1	—
Production	(38.1)	(33.4)	(4.7)	—
December 31, 2020	266.5	240.6	25.9	—
Revisions of previous estimates	**39.3**	**31.1**	**7.5**	**0.7**
Extensions and discoveries	**14.1**	**13.5**	**0.6**	**—**
Purchases of properties	**6.4**	**1.3**	**5.2**	**—**
Production	**(34.9)**	**(31.5)**	**(3.3)**	**(0.1)**
December 31, 2021 [1]	**291.5**	**255.0**	**35.9**	**0.6**
Proved developed crude oil reserves:				
December 31, 2018	249.3	189.0	23.3	37.0
December 31, 2019	230.9	205.0	25.1	0.8
December 31, 2020	179.8	161.4	18.4	—
December 31, 2021 [2]	**191.5**	**174.9**	**16.0**	**0.5**
Proved undeveloped crude oil reserves:				
December 31, 2018	183.2	137.5	31.7	14.0
December 31, 2019	193.0	172.8	20.2	—
December 31, 2020	86.7	79.2	7.5	—
December 31, 2021 [3]	**99.9**	**80.0**	**19.8**	**0.1**

[1] Includes total proved reserves of 16.6 MMBO for Total and United States attributable to the noncontrolling interest in MP GOM.
[2] Includes proved developed reserves of 14.6 MMBO for Total and United States attributable to the noncontrolling interest in MP GOM.
[3] Includes proved undeveloped reserves of 2.0 MMBO 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 2 – Summary of Proved Crude Oil Reserves Based on Average Prices for 2018 – 2021 – Continued

2021 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates - The positive crude oil reserves revisions in 2021 resulted predominantly from impacts of higher commodity prices in the U.S., which partially reversed the 2020 capital allocation reductions, and improved well performance in the U.S. Gulf of Mexico.

Extensions and discoveries - In 2021, proved oil reserves were added for drilling and expansion activities predominantly in the U.S. at the Eagle Ford Shale and the Gulf of Mexico.

Purchases and sales of properties - In 2021, the Company acquired incremental working interest in Terra Nova offshore Canada and in the U.S. Gulf of Mexico.

2020 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates - The negative crude oil reserves revisions in 2020 resulted predominantly from lower crude oil prices and lower capital allocation to Onshore shale properties over the next 5 years causing the removal of numerous proved undeveloped locations, partially offset by improved well performance in the Gulf of Mexico. The 2020 negative oil revision in the U.S. was primarily attributable to lower capital allocation in the Eagle Ford Shale, and the negative revision in Canada was primarily attributable to the Kaybob Duvernay. Lower commodity prices also resulted in negative oil reserves revisions in the U.S offshore and Canada offshore.

Extensions and discoveries - In 2020, proved oil reserves were added for drilling activities predominantly in the U.S. offshore and the Eagle Ford Shale. Proved oil reserves were also added for drilling activities in Canada offshore.

Purchases and sales of properties - In 2020, the Company divested partial working interest in an undeveloped well in the Gulf of Mexico.

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.

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 2018 – 2021

(Millions of barrels)	Total	United States	Canada	Malaysia and Other
Proved developed and undeveloped NGL reserves:				
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	—
Purchase of properties	5.2	5.2	—	—
Production	(4.5)	(3.9)	(0.5)	(0.1)
December 31, 2019	56.1	52.8	3.3	—
Revisions of previous estimates	(16.4)	(17.1)	0.7	—
Extensions and discoveries	2.8	2.7	0.1	—
Production	(4.2)	(3.7)	(0.5)	—
December 31, 2020	38.2	34.6	3.6	—
Revisions of previous estimates	**1.4**	**1.4**	**—**	**—**
Extensions and discoveries	**2.5**	**2.4**	**0.1**	**—**
Purchases of properties	**0.1**	**0.1**	**—**	**—**
Production	**(3.8)**	**(3.4)**	**(0.4)**	**—**
December 31, 2021 [1]	**38.4**	**35.1**	**3.3**	**—**
Proved developed NGL reserves:				
December 31, 2018	27.3	24.9	1.7	0.7
December 31, 2019	28.1	26.2	1.9	—
December 31, 2020	28.7	25.5	3.2	—
December 31, 2021 [2]	**28.4**	**25.6**	**2.8**	**—**
Proved undeveloped NGL reserves:				
December 31, 2018	26.9	22.7	4.2	—
December 31, 2019	28.0	26.6	1.4	—
December 31, 2020	9.5	9.1	0.4	—
December 31, 2021 [3]	**10.0**	**9.5**	**0.5**	—

[1] Includes total proved reserves of 0.7 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.
[2] Includes proved developed reserves of 0.6 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.
[3] Includes proved undeveloped reserves of 0.1 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 2018 – 2021 – Continued

2021 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates - The positive NGL reserves revisions in 2021 resulted predominantly from impacts of higher commodity prices, which partially reversed the 2020 capital allocation reductions, and improved well performance in the U.S. Gulf of Mexico.

Extensions and discoveries - In 2021, proved NGL reserves were added for drilling and expansion activities predominantly in the U.S. Eagle Ford Shale.

Purchases and sales of properties - In 2021, the Company acquired incremental working interest in the U.S. Gulf of Mexico.

2020 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates - The negative NGL reserves revisions in 2020 resulted predominantly from lower crude oil prices and lower capital allocation to Onshore shale properties over the next 5 years causing the removal of numerous proved undeveloped locations, partially offset by improved well performance in the Gulf of Mexico. The 2020 negative NGL revision in the U.S. was primarily attributable to lower capital allowance in the Eagle Ford Shale. The positive revision in Canada was primarily attributable to higher yields at the Kaybob Duvernay due to improved plant recoveries.

Extensions and discoveries - In 2020, proved NGL reserves were added for drilling activities predominantly in the U.S. at the Eagle Ford Shale.

Purchases and sales of properties - In 2020, the Company divested partial working interest in an undeveloped well in the Gulf of Mexico.

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.

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

Schedule 4 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2018 – 2021

(*Billions of cubic feet*)	Total	United States	Canada	Malaysia and Other
Proved developed and undeveloped natural gas reserves:				
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	2,069.7	416.8	1,652.9	—
Revisions of previous estimates	(245.4)	(76.2)	(169.2)	—
Extensions and discoveries	767.2	14.0	753.2	—
Production	(129.8)	(34.4)	(95.4)	—
December 31, 2020	2,461.0	319.5	2,141.5	—
Revisions of previous estimates	**(562.2)**	**18.7**	**(581.0)**	**0.2**
Extensions and discoveries	**556.7**	**13.5**	**543.2**	**—**
Purchases of properties	**5.4**	**1.5**	**3.9**	**—**
Sales of properties	**(4.4)**	**—**	**(4.4)**	**—**
Production	**(134.2)**	**(32.8)**	**(101.4)**	**—**
December 31, 2021 [1,4]	**2,322.3**	**320.3**	**2,001.8**	**0.2**
Proved developed natural gas reserves:				
December 31, 2018	921.6	198.3	595.0	128.3
December 31, 2019	1,279.8	253.1	1,026.7	—
December 31, 2020	1,213.8	260.2	953.6	—
December 31, 2021 [2]	**1,196.0**	**248.1**	**947.7**	**0.2**
Proved undeveloped natural gas reserves:				
December 31, 2018	1,222.0	110.7	771.4	339.9
December 31, 2019	789.9	163.7	626.2	—
December 31, 2020	1,247.2	59.3	1,187.9	—
December 31, 2021 [3]	**1,126.4**	**72.2**	**1,054.1**	**—**

[1] Includes total proved reserves of 6.1 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.
[2] Includes proved developed reserves of 5.4 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.
[3] Includes proved undeveloped reserves of 0.7 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.
[4] Includes proved natural gas reserves to be consumed in operations as fuel of 78.7 BCF and 74.0 BCF for the U.S. and Canada, respectively, with 1.7 BCF attributable to the noncontrolling interest in MP GOM.

Schedule 4 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2018 – 2021 – Continued

2021 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates - The negative natural gas reserves revisions in 2021 resulted predominantly from accelerated royalty incentive payouts due to higher commodity prices at Tupper Montney.

Extensions and discoveries - In 2021, proved equivalent reserves were added for drilling and expansion activities predominantly in Canada at Tupper Montney as well as in the U.S. at the Eagle Ford Shale and the Gulf of Mexico.

Purchases and sales of properties - In 2021, the Company acquired incremental working interest at Terra Nova offshore Canada and in the U.S. Gulf of Mexico.

2020 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates - The negative natural gas reserves revisions in 2020 resulted predominantly from lower crude oil prices and lower capital allocation to Onshore shale properties over the next 5 years causing the removal of numerous proved undeveloped locations, partially offset by improved well performance in the Gulf of Mexico. The 2020 negative natural gas revision in the U.S. was primarily attributable to lower capital allocation in the Eagle Ford Shale which offset positive natural gas revisions in the Gulf of Mexico. The negative revision in Canada was primarily attributable to the Kaybob Duvernay.

Extensions and discoveries - In 2020, proved natural gas reserves were added for drilling and expansion activities predominantly in Canada at Tupper Montney as well as in the U.S. at the Eagle Ford Shale.

Purchases and sales of properties - In 2020, the Company divested partial working interest in an undeveloped well in the Gulf of Mexico.

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.

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 [1]	Other	Total
Year ended December 31, 2021				
Property acquisition costs				
Unproved	**$ 8.8**	**—**	**—**	**8.8**
Proved	**19.9**	**(20.4)**	**—**	**(0.5)**
Total acquisition costs	**28.7**	**(20.4)**	**—**	**8.3**
Exploration costs [2]	**31.7**	**0.4**	**30.1**	**62.2**
Development costs [2]	**513.2**	**102.4**	**3.7**	**619.3**
Total costs incurred	**573.6**	**82.4**	**33.8**	**689.8**
Charged to expense				
Dry hole expense	**17.3**	**—**	**—**	**17.3**
Geophysical and other costs	**13.1**	**0.4**	**19.3**	**32.8**
Total charged to expense	**30.4**	**0.4**	**19.3**	**50.1**
Property additions	**$ 543.2**	**82.0**	**14.5**	**639.7**
Year ended December 31, 2020				
Property acquisition costs				
Unproved	$ 6.5	0.5	7.3	14.3
Proved	0.2	—	—	0.2
Total acquisition costs	6.7	0.5	7.3	14.5
Exploration costs [2]	34.3	(0.4)	24.7	58.6
Development costs [2]	609.2	120.8	6.8	736.8
Total costs incurred	650.2	120.9	38.8	809.9
Charged to expense				
Geophysical and other costs	14.3	0.7	23.6	38.6
Total charged to expense	14.3	0.7	23.6	38.6
Property additions	$ 635.9	120.2	15.2	771.3
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 [2]	44.8	6.4	67.4	118.6
Development costs [2]	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

[1] 2021 Canada proved property acquisitions represents cash received from divesting partners on acquisition of an additional 7.525% working interest at Terra Nova as part of the sanction of an asset life extension project.

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 – Continued

[2] Includes noncash asset retirement costs as follows:

2021					
Exploration costs	**$**	**—**	**—**	**—**	**—**
Development costs		**23.7**	**29.3**	**1.4**	**54.4**
	$	**23.7**	**29.3**	**1.4**	**54.4**
2020					
Exploration costs	$	—	—	—	—
Development costs		12.8	1.9	—	14.7
	$	12.8	1.9	—	14.7
2019					
Exploration costs	$	—	—	—	—
Development costs		75.8	3.8	—	79.6
	$	75.8	3.8	—	79.6

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, 2021				
Revenues				
Crude oil and natural gas liquids sales	**$ 2,199.7**	**228.9**	**4.9**	**2,433.5**
Natural gas sales	**121.8**	**245.9**	**—**	**367.7**
Total oil and natural gas revenues	**2,321.5**	**474.8**	**4.9**	**2,801.2**
Other operating revenues	**16.0**	**1.5**	**—**	**17.5**
Total revenues	**2,337.5**	**476.3**	**4.9**	**2,818.7**
Costs and expenses				
Lease operating expenses	**406.4**	**136.3**	**(3.2)**	**539.5**
Severance and ad valorem taxes	**39.6**	**1.6**	**—**	**41.2**
Transportation, gathering and processing	**126.5**	**60.5**	**—**	**187.0**
Exploration costs charged to expense	**30.4**	**0.4**	**19.3**	**50.1**
Undeveloped lease amortization	**11.1**	**0.2**	**7.6**	**18.9**
Depreciation, depletion and amortization	**616.5**	**163.8**	**1.8**	**782.1**
Accretion of asset retirement obligations	**36.9**	**9.7**	**—**	**46.6**
Impairment of assets	**—**	**171.3**	**18.0**	**189.3**
Selling and general expenses	**20.5**	**16.5**	**6.6**	**43.6**
Other expenses (benefits)	**99.4**	**(66.2)**	**(2.2)**	**31.0**
Total costs and expenses	**1,387.3**	**494.1**	**47.9**	**1,929.3**
Results of operations before taxes	**950.2**	**(17.8)**	**(43.0)**	**889.4**
Income tax expense (benefit)	**183.9**	**(1.7)**	**(9.5)**	**172.7**
Results of operations	**$ 766.3**	**(16.1)**	**(33.5)**	**716.7**
Year ended December 31, 2020				
Revenues				
Crude oil and natural gas liquids sales	$ 1,335.8	174.0	1.8	1,511.6
Natural gas sales	69.4	170.6	—	240.1
Total oil and natural gas revenues	1,405.3	344.6	1.8	1,751.7
Other operating revenues	6.5	1.2	—	7.7
Total revenues	1,411.8	345.8	1.8	1,759.4
Costs and expenses				
Lease operating expenses	476.9	121.6	1.6	600.1
Severance and ad valorem taxes	27.2	1.3	—	28.5
Transportation, gathering and processing	127.7	44.7	—	172.4
Restructuring expenses	1.2	—	—	1.2
Exploration costs charged to expense	35.5	0.6	23.6	59.7
Undeveloped lease amortization	17.2	0.4	9.2	26.8
Depreciation, depletion and amortization	749.4	213.2	2.3	964.9
Accretion of asset retirement obligations	36.6	5.6	—	42.2
Impairment of assets	1,152.5	—	39.7	1,192.2
Selling and general expenses	24.6	17.1	7.1	48.8
Other expenses	21.5	(2.3)	1.8	21.0
Total costs and expenses	2,670.3	402.2	85.3	3,157.8
Results of operations before taxes	(1,258.5)	(56.4)	(83.5)	(1,398.4)
Income tax expense (benefit)	(244.2)	(21.4)	2.1	(263.5)
Results of operations	$ (1,014.3)	(35.0)	(85.6)	(1,134.9)

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
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, 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	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

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

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, 2021				
Future cash inflows	**$ 18,449.1**	**7,203.5**	**44.0**	**25,696.7**
Future development costs	**(1,164.3)**	**(521.1)**	**(1.5)**	**(1,686.8)**
Future production costs	**(7,140.6)**	**(3,525.8)**	**(9.1)**	**(10,675.4)**
Future income taxes	**(1,024.4)**	**(565.4)**	**(3.0)**	**(1,592.8)**
Future net cash flows	**9,119.9**	**2,591.3**	**30.4**	**11,741.6**
10% annual discount for estimated timing of cash flows	**(3,264.9)**	**(1,169.3)**	**(8.5)**	**(4,442.7)**
Standardized measure of discounted future net cash flows	**$ 5,855.1**	**1,422.0**	**21.9**	**7,299.0**
December 31, 2020				
Future cash inflows	$ 9,976.7	4,617.5	—	14,594.2
Future development costs	(1,289.8)	(404.3)	—	(1,694.1)
Future production costs	(5,777.5)	(2,634.6)	—	(8,412.1)
Future income taxes	—	(166.8)	—	(166.8)
Future net cash flows	2,909.4	1,411.8	—	4,321.2
10% annual discount for estimated timing of cash flows	(1,079.2)	(623.4)	—	(1,702.6)
Standardized measure of discounted future net cash flows	$ 1,830.2	788.4	—	2,618.6
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

[1] Includes noncontrolling interest in MP GOM.

[2] Totals within the table may not add as a result of rounding.

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 – 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)	**2021**	2020	2019
Net changes in prices and production costs [2]	**$ 5,962.1**	(5,942.1)	(2,993.9)
Net changes in development costs	**(503.6)**	2,215.1	(675.7)
Sales and transfers of oil and natural gas produced, net of production costs	**(2,220.5)**	(1,123.1)	(2,163.8)
Net change due to extensions and discoveries	**908.5**	568.5	1,221.9
Net change due to purchases and sales of proved reserves	**63.1**	(14.6)	(628.1)
Development costs incurred	**619.3**	736.8	1,282.4
Accretion of discount	**267.2**	699.3	1,002.0
Revisions of previous quantity estimates	**277.1**	(1,461.3)	(71.2)
Net change in income taxes	**(692.8)**	1,112.4	574.1
Net increase (decrease)	**4,680.4**	(3,209.0)	(2,452.3)
Standardized measure at January 1	**2,618.6**	5,827.6	8,279.9
Standardized measure at December 31	**$ 7,299.0**	2,618.6	5,827.6

[1] Includes noncontrolling interest in MP GOM.
[2] The average prices used for 2021 were $66.56 per barrel for NYMEX crude oil (WTI), and $3.60 per Mcf for natural gas (Henry Hub).The average prices used for 2020 were $39.57 per barrel for NYMEX crude oil (WTI), and $1.98 per Mcf for natural gas (Henry Hub). 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).

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, 2021				
Unproved oil and natural gas properties	**$ 602.8**	**17.7**	**141.7**	**762.2**
Proved oil and natural gas properties	**14,690.7**	**4,865.1**	**100.0**	**19,655.8**
Gross capitalized costs	**15,293.5**	**4,882.8**	**241.7**	**20,418.0**
Accumulated depreciation, depletion and amortization				
Unproved oil and natural gas properties	**(109.1)**	**—**	**(22.0)**	**(131.1)**
Proved oil and natural gas properties	**(8,821.5)**	**(3,320.5)**	**(69.0)**	**(12,211.0)**
Net capitalized costs	**$ 6,362.9**	**1,562.3**	**150.7**	**8,075.9**
December 31, 2020				
Unproved oil and natural gas properties	$ 646.0	22.2	137.5	805.7
Proved oil and natural gas properties	14,011.4	4,619.4	23.8	18,654.6
Gross capitalized costs	14,657.4	4,641.6	161.3	19,460.3
Accumulated depreciation, depletion and amortization				
Unproved oil and natural gas properties	(105.0)	—	(14.5)	(119.5)
Proved oil and natural gas properties	(8,166.5)	(2,944.3)	(20.7)	(11,131.5)
Net capitalized costs	$ 6,385.9	1,697.3	126.1	8,209.3

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 [1,2]
Year ended December 31, 2021						
Revenue from contracts with customers	**$**	**592.5**	**758.8**	**687.6**	**762.3**	**2,801.2**
Income (loss) from continuing operations before income taxes		**(355.2)**	**(38.1)**	**174.9**	**261.3**	**42.9**
Income (loss) from continuing operations		**(267.0)**	**(26.9)**	**138.0**	**204.7**	**48.8**
Net income (loss) including noncontrolling interest		**(266.8)**	**(27.0)**	**137.3**	**204.0**	**47.5**
Net income (loss) attributable to Murphy		**(287.4)**	**(63.1)**	**108.4**	**168.4**	**(73.7)**
Income (loss) from continuing operations per Common share						
Basic		**(1.87)**	**(0.41)**	**0.70**	**1.09**	**(0.47)**
Diluted		**(1.87)**	**(0.41)**	**0.70**	**1.08**	**(0.47)**
Net income (loss) per Common share [3]						
Basic		**(1.87)**	**(0.41)**	**0.70**	**1.09**	**(0.48)**
Diluted		**(1.87)**	**(0.41)**	**0.70**	**1.09**	**(0.48)**
Cash dividend per Common share		**0.125**	**0.125**	**0.125**	**0.125**	**0.50**
Year ended December 31, 2020						
Revenue from contracts with customers	$	600.6	285.7	425.3	440.1	1,751.7
Income (loss) from continuing operations before income taxes		(595.4)	(417.9)	(328.4)	(207.3)	(1,549.0)
Income (loss) from continuing operations		(503.8)	(323.1)	(265.9)	(162.5)	(1,255.3)
Net income including noncontrolling interest		(508.7)	(324.4)	(266.6)	(162.7)	(1,262.4)
Net income attributable to Murphy		(416.1)	(317.2)	(243.5)	(171.9)	(1,148.8)
Income (loss) from continuing operations per Common share						
Basic		(2.68)	(2.05)	(1.58)	(1.11)	(7.43)
Diluted		(2.68)	(2.05)	(1.58)	(1.11)	(7.43)
Net income (loss) per Common share						
Basic		(2.71)	(2.06)	(1.59)	(1.11)	(7.48)
Diluted		(2.71)	(2.06)	(1.59)	(1.11)	(7.48)
Cash dividend per Common share		0.25	0.125	0.125	0.125	0.625

[1] Revenue from contracts with customers, Income (loss) from continuing operations before income taxes, Income (loss) from continuing operations and Net income (loss) including noncontrolling interest include results attributable to the noncontrolling interest in MP GOM.
[2] 2020 results include impairment charges of $1,206.3 million as a result of declines in future oil and natural gas prices at the time of impairment (principally driven by reduced demand in response to the COVID-19 pandemic - see Risk Factors).
[3] The sum of quarterly net income (loss) per share may not agree with total year net income (loss) per share as each quarterly computation is based on the weighted average of common shares outstanding.

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
2021						
Deducted from asset accounts:						
Allowance for doubtful accounts	**$**	**1.6**	**—**	**—**	**—**	**1.6**
Deferred tax asset valuation allowance		**106.4**	**4.8**	**—**	**—**	**111.2**
2020						
Deducted from asset accounts:						
Allowance for doubtful accounts	$	1.6	—	—	—	1.6
Deferred tax asset valuation allowance		103.1	3.3	—	—	106.4
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

[1] The amount in 2019 for deferred tax asset valuation allowance is primarily associated with utilization of 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

BOEPD - Barrel of oil equivalent per day

FASB - Financial Accounting Standards Board

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

WTI - West Texas Intermediate

MURPHY OIL CORPORATION
ANNUAL INCENTIVE PLAN

SECTION 1. PURPOSE OF THE PLAN

The purpose of the Murphy Oil Corporation Annual Incentive Compensation Plan is to provide incentive compensation to those officers, executives, and key employees who, in the opinion of the Company, contribute significantly to the growth and success of the Company; to attract and retain individuals of outstanding ability; and to align the interests of those who hold positions of major responsibility in the Company with the interests of Company stockholders.

SECTION 2. DEFINITIONS

Unless the context otherwise indicates, the following definitions shall be applicable:

"Award" shall mean a right granted to a Participant pursuant to Section 5 of the Plan to receive a cash payment from the Company (or a Subsidiary) based upon the extent to which the Participant's Performance Goal(s) are achieved during the relevant Performance Period, subject to the Committee's discretion pursuant to Section 5(D) of the Plan.

"Base Salary" shall mean, with respect to a Participant, the base salary actually paid to the Participant during the Plan Year as shown in the payroll/personnel records of the Company.

"Board" shall mean the Board of Directors of Murphy Oil Corporation.

"Code" shall mean the Internal Revenue Code of 1986, as amended from time to time; references to particular sections of the Code include references to regulations and rulings thereunder and to successor provisions.

"Committee" shall mean the Executive Compensation Committee of the Board or any other committee of the Board designated by resolution of the Board to administer the Plan.

"Company" shall mean Murphy Oil Corporation (a Delaware corporation), its successors and assigns, and each of its Subsidiaries designated by the Committee for participating in this Plan.

"Disability" shall mean a physical or mental impairment sufficient to make a Participant eligible for benefits under the Company's Long-Term Disability Plan.

"Employee" shall mean any regular employee of the Company.

"GAAP" shall mean generally accepted accounting principles set forth in the opinions, statements and pronouncements of the Financial Accounting Standards Board, United States (or predecessors or successors thereto or agencies with similar functions), or in such other statements by such other entity as may be in general use by significant segments of the accounting profession, which are applicable to the circumstances as of the date of determination and in any event applied in a manner consistent with the application thereof used in the preparation of the Company's financial statements.

"Maximum Performance Level" shall mean the level of performance achievement of the Performance Goals as determined by the Committee in its sole discretion.

"Participant" shall mean any officer, executive, or key Employee of the Company selected by the Committee to receive an Award under the Plan.

"Performance Goal" shall mean a performance objective established by the Committee for a particular Participant for a Performance Period pursuant to Section 5 of the Plan for the purpose of determining the extent to which an Award has been earned for such Performance Period. Each Performance Goal may consist of (a) "Performance Criteria," as defined in Section 5(B) of the Plan, which are one or more measures related to individual, business unit, or Company performance, and (b) a "Performance Target," which is the level at which the relevant Performance Criteria must be achieved for purposes of determining whether a cash payment is to be made under an Award, which may be stated as a threshold level below which no payment will be made, a maximum level at or above which full payment will be made, and intermediate targets which will result in payment between such threshold and maximum level.

"Performance Period" shall mean a Plan Year or, for a Participant who becomes a Participant after the first day of the Plan Year because he or she was promoted, newly hired or otherwise selected by the Committee to receive an Award under the Plan after the first day of the Plan Year, such portion of the Plan Year as determined by the Committee.

"Plan" shall mean the Murphy Oil Corporation Annual Incentive Compensation Plan, as amended from time to time.

"Plan Year" shall mean the fiscal year of the Company.

"Retirement" shall mean termination of employment at an age and length of service such that the Participant would be eligible to an immediate commencement of benefit payments under the formula of the Company's defined benefit pension plan available generally to its Employees, whether or not such individual actually elects to commence such payments.

"Subsidiary" shall mean any entity that is directly or indirectly controlled by the Company, as determined by the Committee.

"Target Award Opportunity" shall mean the percent of Base Salary to be awarded to each Participant in the Plan upon achievement of one hundred percent (100%) of the Performance Goals at one hundred percent (100%) performance attainment established within the Performance Criteria of the Plan.

"Threshold Performance Level" shall mean the level of achievement of the Performance Goals within the Performance Criteria below which no awards may be paid to a Participant.

SECTION 3. PLAN ADMINISTRATION

A. The Committee.

The Plan will be administered by the Committee. In accordance with and subject to the provisions of the Plan, the Committee will have full authority and discretion with respect to Awards made under the Plan, including without limitation the following: (a) selecting the officers, executives, or other key Employees to be Participants; (b) establishing the terms of each Award; (c) determining the time or times when Awards will be granted; and (d) establishing the restrictions and other conditions to which the payment of Awards may be subject. Subject to Section 9, the Committee will have no authority under the Plan to amend or modify, in any manner, the terms of any outstanding Award; provided, however, that the Committee shall have the authority to reduce or eliminate the compensation or other economic benefit otherwise due pursuant to an Award. Each determination, interpretation, or other action made or taken by the Committee pursuant to the provisions of the Plan will be conclusive and binding for all purposes and on all persons, and no member of the Committee will be liable for any action or determination made in good faith with respect to the Plan or any Award granted under the Plan.

B. Adjustments

In the event of (a) any merger, reorganization, consolidation, recapitalization, liquidation, reclassification, stock dividend, stock split, special or extraordinary cash dividend, combination of shares, rights offering, extraordinary dividend (including a spin-off), or other similar change affecting the Company's shares; (b) any purchase, acquisition, sale, or disposition of a significant amount of assets other than in the ordinary course of business, or of a significant business; (c) any change resulting from the accounting effects of discontinued operations, material events or transactions that are either unusual in nature or infrequently occurring, or both, changes in accounting, or restatement of earnings, in each case as determined under GAAP; or (d) any charge or credit resulting from an item which is classified as "non-recurring," "restructuring," or similar unusual item on the Company's audited annual Statement of Income which, in the case of (a) – (d), results in a change in the components of the calculations of any of the Performance Criteria, as established by the Committee, in each case with respect to the Company or any other entity whose performance is relevant to the achievement of any Performance Goal included in an Award, the Committee (or, if the Company is not the surviving corporation in any such transaction, a committee of the Board of Directors of the surviving corporation) shall, without the consent of any affected Participant, amend or modify the terms of any outstanding Award that includes any Performance Goal based in whole or in part on the financial performance of the Company (or any Subsidiary or division thereof) or such other entity so as equitably to reflect such event or events, such that the criteria for evaluating such financial performance of the Company or such other entity (and the achievement of the corresponding Performance Goal) will be substantially the same (as determined by the Committee or the committee of the Board of Directors of the surviving corporation) following such event as prior to such event.

SECTION 4. PARTICIPATION

The Participants for any Performance Period shall be those officers, executives, and key Employees who are granted Awards by the Committee under the Plan for such Performance Period.

SECTION 5. GRANT OF AWARDS

A. Nature of Awards

An Award granted under the Plan shall provide for a cash payment to be made solely on account of the attainment of one or more Performance Goals included in such Award, subject to the Committee's authority pursuant to Section 3 and Section 6 of the Plan.

B. Performance Criteria

The "Performance Criteria" for Awards made under the Plan shall be determined in the sole discretion of the Committee and may include, without limitation, the following measurements, or changes in such measurements between different Plan Years (or combination thereof) as applied to the Company or a Subsidiary, and in either case either on an absolute basis or relative basis (as compared to an external benchmark or performance of a designated peer group of companies).

(a) Earnings (either in aggregate or on a per-share basis);

(b) Net income;

(c) Operating income;

(d) Operating profit;

(e) Cash flow;

(f) Stockholder returns (including return on assets, investment, invested capital, and equity, (including income applicable to common stockholders or other class of stockholders);

(g) Return measures (including return on assets, equity, or invested capital);

(h) Earnings before or after either, or any combination of, interest, taxes, depreciation, or amortization (EBITDA);

(i) Gross revenues;

(j) Share price (including growth measures and total stockholder return or attainment by the shares of a specified value for a specified period of time);

(k) Reduction in expense levels in each case, where applicable, determined either on a Company-wide basis or in respect of any one or more Subsidiaries or business units thereof;

(l) Economic value;

(m) Market share;

(n) Annual net income to common stock;

(o) Earnings per share;

(p) Annual cash flow provided by operations;

(q) Changes in annual revenue;

(r) Strategic business criteria, consisting of one or more objectives based on meeting specified revenue, market penetration, geographic business expansion goals, objectively identified project milestones, production volume levels, cost targets, and goals relating to acquisitions or divestitures;

(s) Operational measures tied to exploration and production including changes in proven reserves, drilling costs, lifting costs, safety and accident rates, environmental compliance, and exploration costs; and

(t) Operating and maintenance cost management.

The Committee, on the grant date of an Award, may designate whether a particular Performance Criteria is to be measured on a pre-tax basis or post-tax basis. Further, the Committee may select any one or more of the Performance Criteria applicable to a Participant and Performance Criteria may differ for Awards for one Participant to the next.

C. Establishment of Performance Goals

The Committee shall in its discretion determine for each Participant:

(a) the Performance Goal(s) for the Participant, which may include one or more of the Performance Criteria set forth in Section 5(B) of the Plan, and the Performance Target for each Performance Criteria;

(b) if more than one Performance Goal is specified for a Participant, the relative weight assigned to each Performance Goal; and

(c) the cash Award expressed as a percentage of the base salary for the Participant for the Performance Period, provided that the Committee shall also place a maximum dollar amount on such Award, which may not exceed four million dollars ($4,000,000) for each Participant.

D. Individual Award Targets and Adjustments

(a) Each Participant shall have a Target Award Opportunity expressed as a percentage of the Participant's Base Salary. In addition, the Plan shall stipulate for each Participant a Target Award Opportunity as well as, if applicable, a Threshold Performance Level and Maximum Performance Level associated with each Performance Goal established for the Plan Year.

(b) Individual Target Award Opportunities, Threshold Performance Levels and Maximum Performance Levels may vary by Participant and may reflect the Participant's position, level of responsibility, areas of accountability and other considerations.

(c) The Committee may exercise full discretion, both positive and negative, in adjusting any individual Participant's Award; provided, that the amount of positive discretion cannot exceed twenty five percent (25%) of the earned Award amount and in no event may such Participant's Award exceed the Maximum Performance Level for such Award.

SECTION 6. PAYMENT OF AWARDS

As soon as practicable after the Committee has received the appropriate financial and other data after the end of a Plan Year, the Committee will for each Participant certify in writing the extent to which the applicable Performance Goals for such Participant have been met and, subject to Section 5 of the Plan, the corresponding amount of the Award earned by such Participant. Payment of each Award in a cash lump sum, less applicable withholding taxes pursuant to Section 8 of the Plan, shall be made in the calendar year immediately following the applicable Plan Year as soon as practicable after the Committee's certification of the Performance Goals.

SECTION 7. EFFECT OF TERMINATION OF EMPLOYMENT

A. Termination Due to Death, Disability, or Retirement

In the event a Participant's employment with the Company and all Subsidiaries is terminated by reason of death, Disability, or Retirement during a Performance Period, the Participant (or the Participant's estate) (subject to the Committee's discretion as allowed by Section 3.A of the Plan) shall be paid (pursuant to Section 6 of the Plan after the completion of the Plan Year) a percentage of the amount earned according to the terms of the Award equal to the portion of the Performance Period through the Participant's death, Disability, or Retirement, as the case may be, as determined by the Committee.

B. Termination for Reasons Other than Death, Disability, or Retirement

In the event a Participant's employment is terminated with the Company and all Subsidiaries prior to the Committee's certification of the Performance Goals for any reason other than death, Disability, or Retirement, or a Participant is in the employ of a Subsidiary and the Subsidiary ceases to be a Subsidiary of the Company (unless the Participant continues in the employ of the Company or another Subsidiary), the Participant's Award for the applicable Performance Period shall be immediately forfeited and the Participant shall have no right to any payment thereafter; provided, however, that under such circumstances, the Committee may, in its sole discretion, pay the Participant an amount not to exceed a percentage of the amount earned according to the terms of the Award equal to the portion of the Performance Period through the Participant's termination.

SECTION 8. PAYMENT OF WITHHOLDING TAXES

The Company shall withhold and deduct from the payment made pursuant to an Award or from future wages of the Participant (or from other amounts that may be due and owing to the Participant from the Company or a Subsidiary), or make other arrangements for the collection of, all legally required amounts necessary to satisfy any and all federal, state, and local withholding and employment-related tax requirements attributable to any payment made pursuant to an Award.

SECTION 9. PLAN AMENDMENT, MODIFICATION, AND TERMINATION

The Board may suspend or terminate the Plan or any portion thereof at any time, and may amend the Plan from time to time in such respects as the Board may deem advisable in order that Awards under the Plan will conform to any change in applicable laws or regulations or in any other respect the Board may deem to be in the best interests of the Company. Any termination, suspension, or amendment of the Plan may adversely affect any outstanding Award without the consent of the affected Participant.

SECTION 10. NON-FUNDED, UNSECURED OBLIGATION

A Participant's only interest under the Plan shall be the right to receive a cash payment under an Award pursuant to the terms of the Award and the Plan (subject to the authority of the Committee pursuant to Section 3, Section 8 and Section 9 of the Plan). No portion of the amount payable to Participants under the Plan shall be held by the Company or any Subsidiary in trust or escrow or any other form of asset segregation. To the extent that a Participant acquires a right to receive such a cash payment under the Plan, such right shall be no greater than the right of any unsecured, general creditor of the Company.

SECTION 11. EFFECTIVE DATE AND DURATION OF THE PLAN

The Plan was adopted by the Board on December 7, 2021, with an effective date of January 1, 2022, and will remain in effect until such time as the Plan is terminated by the Board. Any payments pursuant to Awards outstanding upon termination of the Plan may continue to be made in accordance with the terms of the Awards, subject to the authority of the Committee pursuant to Section 3 and Section 9 of the Plan.

SECTION 12. SECTION 409A OF THE CODE

With respect to Awards subject to Section 409A of the Code, the Plan is intended to comply with the requirements of Section 409A of the Code, and the provisions of the Plan and any Award shall be interpreted in a manner that satisfies the requirements of Section 409A of the Code, and the Plan shall be operated accordingly. If any provision of the Plan or any term or condition of any Award would otherwise frustrate or conflict with this intent, the provision, term or condition shall be interpreted and deemed amended so as to avoid this conflict. Notwithstanding anything in the Plan to the contrary, if the Committee considers a Participant to be a "specified employee" under Section 409A of the Code at the time of such Participant's "separation from service" (as defined in Section 409A of the Code), and any amount hereunder is "deferred compensation" subject to Section 409A of the Code, any distribution of such amount that otherwise would be made to such Participant with respect to an Award as a result of such "separation from service" shall not be made until the date that is six months after such "separation from service," except to the extent that earlier distribution would not result in such Participant's incurring interest or additional tax under Section 409A of the Code. If an Award includes a "series of installment payments" (within the meaning of Section 1.409A-2(b)(2)(iii) of the Treasury Regulations), the Participant's right to such series of installment payments shall be treated as a right to a series of separate payments and not as a right to a single payment. Notwithstanding the foregoing, the tax treatment of the benefits provided under the Plan or any Award is not warranted or guaranteed, and in no event shall the Company be liable for all or any portion of any taxes, penalties, interest or other expenses that may be incurred by any Participant on account of non-compliance with Section 409A of the Code.

SECTION 13. CLAWBACK

A Participant whose misconduct results in the Company's having to restate all or a portion of its financial statements, due to material noncompliance with the provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act, the Sarbanes-Oxley Act, or any other applicable law or listing standard, shall immediately forfeit the Participant's Award upon such determination, and such Participant shall be required to reimburse the Company in respect of any payments made under the Plan in the period covered by such financial statements, as determined in each case, by the Committee in good faith. In addition, the Participant's rights, payments and benefits with respect to an Award shall be subject to forfeiture or reimbursement to the Company upon the occurrence of certain specified events, in addition to any otherwise applicable performance conditions applicable to such Award. Such events may include a Participant's violation of material Company policies, breach of non-competition, non-solicitation, confidentiality or other restrictive covenants, or other conduct by the Participant that is detrimental to the business or reputation of the Company and/or its Subsidiaries, as determined in each case by the Committee.

SECTION 14. MISCELLANEOUS

A. Employment

Nothing in the Plan will interfere with or limit in any way the right of the Company or any Subsidiary to terminate the employment or otherwise modify the terms and conditions of the employment of any Employee or Participant at any time, nor confer upon any Employee or Participant any right to continue in the employ of the Company or any Subsidiary.

B. Restrictions or Transfer

Except pursuant to testamentary will or the laws of descent and as otherwise expressly permitted by the Plan, no right or interest of any Participant in an Award will be assignable or transferable, or subjected to any lien, during the lifetime of the Participant, either voluntarily or involuntarily, directly or indirectly, by operation of law or otherwise.

C. Governing Law

Except to the extent in connection with other matters of corporate governance and authority (all of which shall be governed by the laws of the Company's jurisdiction of incorporation), the validity, construction, interpretation, administration, and effect of the Plan and any rules, regulations, and actions relating to the Plan will be governed by and construed exclusively in accordance with the internal, substantive laws of the State of Delaware, without regard to the conflict of law rules of the State of Delaware or any other jurisdiction.

D. Successors

The Plan will be binding upon and inure to the benefit of the successors of the Company and the Participants.

MURPHY OIL CORPORATION
SUBSIDIARIES OF THE REGISTRANT AS OF DECEMBER 31, 2021

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 I.(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

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
t. Murphy Netherlands Holdings B.V.	Netherlands	100.00
(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 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 AC/P 59 Oil Pty. Ltd.	Western Australia	100.00
(5) Murphy Australia EPP43 Oil Pty. Ltd.	Western Australia	100.00
(6) Murphy Australia WA-481-P 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

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the registration statements (Nos. 333-256048 and 333-241837) on Form S-8 and in the registration statement (No. 333-260287) on Form S-3 of our reports dated February 25, 2022, with respect to the consolidated financial statements and financial statement schedule II on Murphy Oil Corporation and the effectiveness of internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 25, 2022

Exhibit 23.2

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS 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. 333-256048 and 333-241837) on Form S-8, the Registration Statement (File No. 333-260287) 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, 2021 and dated January 12, 2022 for Murphy Oil Corporation, which appears in the December 31, 2021 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.
TBPELS Firm Registration No. F-1580

Houston, Texas
February 22, 2022

SUITE 800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799
633 17TH STREET, SUITE 1700 DENVER, COLORADO 80202 TEL (303) 339-8110

McDANIEL

Trond Mathisen
GM - 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 report conducting an audit of the Canadian Oil and Gas Properties for the Greater Tupper Montney Project effective December 31, 2021 and dated January 17, 2022 in the Murphy Oil Corporation Registration Statement Form S-8, No. 333-256048 and 333-241837 and Registration Statement Form S-3, No. 333-260287 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

February 22, 2022
APEGA PERMIT NUMBER: P3145

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 25, 2022

/s/ Roger W. Jenkins
Roger W. Jenkins
Principal Executive Officer

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 25, 2022

/s/ David R. Looney
David R. Looney
Principal Financial Officer

**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, 2021 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 25, 2022

/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, 2021

/s/ Eric T. Nelson
Eric T. Nelson, P.E.
TBPELS License No. 102286
Managing Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

McDANIEL McDANIEL

TBPELS REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA STREET SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 12, 2022

Trond Mathisen
General Manager - Corporate Reserves Group
Murphy Oil Corporation
9805 Katy Freeway, Suite G-200
Houston, TX 77024

Dear Mr. Mathisen:

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, 2021 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 7, 2022 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, 2021. 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 7, 2022. The properties reviewed and included herein by Ryder Scott incorporate Murphy's 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, 2021. Based on the estimates of total net proved reserves prepared by Murphy, the reserves audit conducted by Ryder Scott in this report addresses 40 percent of the total proved developed net reserves on a barrel of oil equivalent, BOE basis and 29 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 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799
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, 2021 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, 2021, 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, 2021

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Audited by Ryder Scott				
U.S. Onshore				
Net Reserves				
Oil/Condensate – MBBL	80,139	2,188	29,906	112,233
Plant Products – MBBL	18,808	383	6,333	25,524
Gas – MMCF	155,669	2,025	41,628	199,322
MBOE	124,892	2,909	43,177	170,978
Gulf of Mexico (GOM)				
Net Reserves				
Oil/Condensate – MBBL	17,211	1,193	34,506	52,910
Plant Products – MBBL	2,763	450	2,564	5,777
Gas – MMCF	57,569	4,726	25,008	87,303
MBOE	29,569	2,431	41,238	73,238

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 67,049 MMcf, or 6.5 percent of the total U.S. Onshore net MBOE and 2,911 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.

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 November 2021, 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 November 2021. 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, 2021 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 reviewed by us for their reasonableness using information furnished by Murphy for this purpose.

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-Offshore	Oil/Condensate	WTI Cushing	$66.56/Bbl	$65.81/BBL	$65.81/BBL
	NGLs	WTI Cushing	$66.56/Bbl	$23.24/BBL	$23.24/BBL
	Gas	Henry Hub	$3.598/MMBTU	$3.54MCF	$3.66/MCF
United States-Onshore	Oil/Condensate	WTI Cushing	$66.56/Bbl	$64.78/BBL	$64.78/BBL
	NGLs	WTI Cushing	$66.56/Bbl	$27.69/BBL	$27.69/BBL
	Gas	Henry Hub	$3.598/MMBTU	$2.21/MCF	$3.33/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 reviewed by us for their reasonableness using information furnished by Murphy for this purpose; information provided included historic operating expenses, pay out balances, and royalty relief information. 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 reviewed by us for their reasonableness using information furnished by Murphy for this purpose. The estimated net cost of abandonment after salvage was included by Murphy for properties where abandonment costs net of salvage were material. The abandonment costs furnished by Murphy were reviewed by us for their reasonableness using information furnished by Murphy for this purpose.

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, 2021. 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, 2021, 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. The data furnished by Murphy were reviewed by us for their reasonableness using information furnished by Murphy for this purpose. 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, 2021 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. However notwithstanding, 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.

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.
TBPELS Firm Registration No. F-1580

/s/ Eric T. Nelson

Eric T. Nelson, P.E.
TBPELS License No. 102286
Managing Senior Vice President **[SEAL]**

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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 2021 continuing education hours, Mr. Nelson attended over 20 hours of training during 2021 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 16 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 June 2019.

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.

EXHIBIT 99.2

MURPHY OIL CORPORATION

Estimated

Future Reserves

Attributable to the 100%

Leasehold Interests of the

Murphy Petrobras GOM JV

SEC Parameters

As of

December 31, 2021

/s/ Eric T. Nelson
Eric T. Nelson, P.E.
TBPELS License No. 102286
Managing Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

McDANIEL McDANIEL

TBPELS REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA STREET SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 12, 2022

Trond Mathisen
General Manager - Corporate Reserves Group
Murphy Oil Corporation
9805 Katy Freeway, Suite G-200
Houston, TX 77024

Dear Mr. Mathisen:

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, 2021 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 7, 2022 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's reserves determinations and are located in federal waters offshore Louisiana and Alabama**.**

The properties reviewed by Ryder Scott account for a portion of Murphy's total net proved reserves as of December 31, 2021. Based on the estimates of total net proved reserves prepared by Murphy, the reserves audit conducted by Ryder Scott in this report addresses 16 percent of the total proved developed net reserves on a barrel of oil equivalent, BOE basis and 5 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 non-controlling interest of Petrobras.

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 reserves 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, 2021 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, 2021, 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 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, 2021

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves to MPGOM				
Oil/Condensate – MBarrels	68,215	5,999	15,608	89,822
Plant Products – MBarrels	2,838	314	638	3,790
Gas – MMcf	23,881	4,223	5,612	33,716
MBOE	75,033	7,017	17,181	99,231

Estimated Net Reserves
Attributable to Murphy’s Leasehold Interests in the
Murphy Petrobras GOM JV (MPGOM)
As of December 31, 2021

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves to MPGOM				
Oil/Condensate – MBarrels	54,762	4,821	13,626	73,209
Plant Products – MBarrels	2,278	252	537	3,067
Gas – MMcf	19,291	3,395	4,900	27,586
MBOE	60,255	5,639	14,980	80,874

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 7,038 MMcf at Murphy's Leasehold Interests of MPGOM, or 1.5 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.

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 October 2021, 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. This method was 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 October 2021. 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, 2021 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 reviewed by us for their reasonableness using information furnished by Murphy for this purpose.

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	$66.56/Bbl	$65.91/Bbl	$65.91/Bbl
	NGLs	WTI Cushing	$66.56/Bbl	$24.11/Bbl	$24.11/Bbl
	Gas	Henry Hub	$3.598/MMBTU	$2.83 /Mcf	$3.79 /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 reviewed by us for their reasonableness using information furnished by Murphy for this purpose; information provided included historic operating expenses, pay out balances, and royalty relief information. 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 reviewed by us for their reasonableness using information furnished by Murphy for this purpose. The estimated net cost of abandonment after salvage was included by Murphy for properties where abandonment costs net of salvage were material. The abandonment costs furnished by Murphy were reviewed by us for their reasonableness using information furnished by Murphy for this purpose.

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, 2021. 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, 2021, 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. The data furnished by Murphy were reviewed by us for their reasonableness using information furnished by Murphy for this purpose. 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, 2021 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. However notwithstanding, 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 Murphy and Petrobras GOM JV (MPGOM).

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.
TBPELS Firm Registration No. F-1580

/s/ Eric T. Nelson

Eric T. Nelson, P.E.
TBPELS License No. 102286
Managing Senior Vice President **[SEAL]**

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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 2021 continuing education hours, Mr. Nelson attended over 20 hours of training during 2021 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 16 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 June 2019.

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 17, 2022

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, 2021

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 Tupper Montney Project located within the Province of British Columbia, Canada. Murphy holds a 99.72 percent working interest in the Greater Tupper Montney Project. Murphy has represented that this property accounts for approximately 45.3 percent of its total company proved reserves on an equivalent barrel basis as of December 31, 2021, 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, 2021, for the same properties as those which we audited. The completion date of our report is January 11, 2022. 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, 2021. 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 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 2021 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$66.56 per barrel and a Brent crude oil benchmark of USD$69.23 per barrel. Specific pricing for each field was adjusted for historical quality and transportation cost differentials, and for currency exchange rates. For total proved reserves in the Greater Tupper Montney Project, the estimated realized prices were CAD$2.83 per Mcf of natural gas, and CAD$70.57 per barrel of natural gas liquids.

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 36.0 percent of the total proved developed net reserves on a barrel of oil equivalent, BOE basis and 58.3 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, 2021
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				
Tupper Montney	-	150,397	609	151,006
Proved Developed Non-Producing				
Tupper Montney	-	-	-	-
Proved Developed				
Tupper Montney	-	150,397	609	151,006
Proved Undeveloped				
Tupper Montney	-	173,272	258	173,530
Total Proved				
Tupper Montney	-	323,669	867	324,536

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, 9,923 Mboe are attributed to fuel gas reserves in the Greater 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 65 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.

McDaniel & Associates Consultants Ltd. (“McDaniel”) has been in the business of providing oil and gas reserves evaluations for over 65 years. Mr. Jared W. B. Wynveen, P. Eng., Executive Vice President has been with the firm since 2006, and has approximately 15 years of experience in the evaluation of oil and gas properties. As a senior engineer of McDaniel, Mr. Wynveen managed the preparation evaluation of the Murphy Oil Corporation properties. Mr. Wynveen is a registered professionals with the Association of Professional Engineers and Geoscientist of Alberta (APEGA) with approximately 15 years of experience with the firm.

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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.

If there are any questions, please contact Jared Wynveen directly at (403) 218-1397.

Sincerely,
McDANIEL & ASSOCIATES CONSULTANTS LTD.
APEGA PERMIT NUMBER: P3145

"signed by J. W. B. Wynveen"

Jared W. B. Wynveen, P.Eng.
Executive Vice President
January 17, 2022

JWBW:jep
[21-0201]

McDANIEL

CERTIFICATE OF QUALIFICATION

I, Jared W. B. Wynveen, Petroleum Engineer of 2200, 255 - 5th Avenue, S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an Executive Vice President of McDaniel & Associates Consultants Ltd., APEGA Permit Number P3145, which Company did prepare, at the request of Murphy Oil Corporation., the report entitled "Murphy Oil Corporation, Evaluation of Canadian Oil and Gas Properties, As of December 31, 2021", dated January 17, 2022, and that I was involved in the preparation of this report. I am also registered as a Responsible Member as outlined by APEGA for McDaniel & Associates Consultant Ltd. APEGA Permit Number 3145.
2. That I attended the Queen's University in the years 2002 to 2006 and that I graduated with a Bachelor of Science degree in Mechanical Engineering, that I am a registered Professional Engineer with the Association of Professional Engineers and Geoscientists of Alberta and that I have in excess of 15 years of experience in oil and gas reservoir studies and evaluations.
3. That I have no direct or indirect interest in the properties or securities of Murphy Oil Corporation, nor do I expect to receive any direct or indirect interest in the properties or securities of Murphy Oil Corporation, or any affiliate thereof.
4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.

[SEAL]

APEGA ID 89207

Calgary, Alberta

Dated: January 17, 2022