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, 2024

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. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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 28, 2024) – $4,465,018,220.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2025 was 145,855,183.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 14, 2025 have been incorporated by reference in Part III herein.

MURPHY OIL CORPORATION

2024 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. In 2013, the United States (U.S.) refining and marketing 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 U.S., Canada and all other countries. Additionally, the Corporate segment includes 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.

As part of the Company’s underlying operations, the Company is continually monitoring its greenhouse gas (GHG) emissions and impact on the environment as well as other social and environmental aspects of its business. See “Sustainability” on page 9.

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 43, 75 through 79, 100 through 104, and 106 through 121 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 and condensate (collectively, crude oil), natural gas and natural gas liquids (NGLs) primarily in the U.S. and Canada and explores for crude oil, natural gas and NGLs in targeted areas worldwide.

During 2024, Murphy’s principal exploration and production activities were conducted in the U.S. by wholly-owned Murphy Exploration & Production Company – USA and its subsidiaries, in Canada by wholly-owned Murphy Oil Company Ltd. and its subsidiaries, and in Brazil, Brunei, Côte d’Ivoire and Vietnam by wholly-owned Murphy Exploration & Production Company – International and its subsidiaries. Murphy’s operations and production in 2024 were in the U.S., Canada and Brunei.

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

Murphy’s worldwide 2024 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 184,293 barrels of oil equivalent per day (BOEPD), a decrease of 4.3% compared to 2023.

For further details on business execution, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations” starting on page 31. For further details on 2024 production and sales volume see pages 35 to 36.

United States

In the U.S., Murphy produces crude oil, natural gas and NGLs primarily from fields in the Gulf of America and in the Eagle Ford Shale area of South Texas. The Company produced 93,184 barrels (BBL) of crude oil and NGLs (collectively, liquids) per day and approximately 82 million cubic feet (MMCF) of natural gas per day in the U.S. in

2024. These amounts represented 89.5% of the Company’s total worldwide liquids and 17.1% of worldwide natural gas production volumes.

Offshore

The Company holds rights to approximately 580 thousand gross acres in the Gulf of America. During 2024, approximately 72% of total U.S. hydrocarbon production was produced at fields in the Gulf of America, of which approximately 90% was derived from ten fields, including the operated Khaleesi, Mormont, Cascade and Chinook, Samurai, Marmalard, Dalmatian and Powerball fields, as well as the non-operated St. Malo, Kodiak and Lucius fields. Total average daily production in the Gulf of America in 2024 was 67,591 BBL of liquids and 57 MMCF of natural gas. At December 31, 2024, Murphy had total proved reserves for Gulf of America fields of 123.2 million BBL of liquids and 93.2 billion cubic feet of natural gas.

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 2024, approximately 28% of total U.S. hydrocarbon production was produced in the Eagle Ford Shale. Total 2024 production in the Eagle Ford Shale area was 25,521 BBL of liquids per day and 24.9 MMCF per day of natural gas. At December 31, 2024, the Company’s proved reserves for the U.S. Onshore business totaled 136.1 million BBL of liquids and 195.7 billion cubic feet of natural gas.

Canada

In Canada, the Company holds working interests in Tupper Montney (100% working interest), Kaybob Duvernay and two non-operated offshore assets – the Hibernia and Terra Nova fields, located offshore Newfoundland and Labrador in the Jeanne d’Arc Basin. During 2023, the Company sold a portion of its working interest in Kaybob Duvernay and the entire 30% non-operated working interest in Placid Montney.

Onshore

Murphy has approximately 139 thousand gross acres of Tupper Montney mineral rights located in northeast British Columbia. In addition, the Company holds a 70% working interest in Kaybob Duvernay lands in Alberta. The Company has approximately 166 thousand gross acres of Kaybob Duvernay mineral rights. Daily production in 2024 in Canada Onshore averaged 3,465 BBL of liquids and 399 MMCF of natural gas. Total Canada Onshore proved liquids and natural gas reserves at December 31, 2024, were approximately 21.4 million BBL and 2.2 trillion cubic feet, respectively.

Offshore

The Company holds a non-operated interest in approximately 133 thousand gross acres offshore Canada. Murphy has a 6.5% working interest in Hibernia Main, a 4.3% working interest in Hibernia South Extension and an 18.0% working interest in Terra Nova. Oil production in 2024 was 7,251 BBL of oil per day for the two offshore Canadian fields. Terra Nova resumed production during the fourth quarter of 2023, following the completion of the asset life extension project. Total proved reserves for Canada Offshore at December 31, 2024 were approximately 20.8 million BBL of liquids and 14.0 billion cubic feet of natural gas.

Brazil

The Company holds a 20% non-operated working 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, SEAL-M-505, SEAL-M-573, SEAL-M-575 and SEAL-M-637). Murphy has a 100% working interest in three blocks in the Potiguar Basin (POT-M-857, POT-M-863 and POT-M-865).

Murphy’s total acreage position in Brazil as of December 31, 2024 is approximately 2.5 million 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 as of December 31, 2024. Oil production in 2024 was 219 BBL of oil per day for Brunei.

Total proved reserves for our Jagus East discovery in Block CA-1 at December 31, 2024 were approximately 0.2 million BBL of liquids and 172 MMCF of natural gas. Block CA-1 covers 2 thousand gross acres.

Vietnam

The Company holds an interest in 7.3 million gross acres, consisting of 65% working interest in Blocks 144 & 145, and a 40% interest in Block 15-1/05 and Block 15-2/17. The Company is the operator of each of the three Production Sharing Contracts (PSCs).

Block 15-1/05 contains the Lac Da Vang (Golden Camel) discovered field in the Cuu Long Basin where, in 2023, the Company received government approval of the field development plan, and the Board of Directors of the Company (the Board) sanctioned the project. Development activity is in progress, with first oil planned in 2026. The Lac Da Trang-1X (White Camel) exploration well was drilled in April 2019 and the Company anticipates drilling the Lac Da Hong-1X (Pink Camel) exploration well in 2025.

In Block 15-2/17, the Company completed its geological and geophysical commitment work, which included 3D seismic reprocessing. In the fourth quarter 2024, the Company drilled an oil discovery at the Hai Su Vang-1X (Golden Sea Lion) exploration well, which encountered approximately 370 feet of net pay from two reservoirs. Additional evaluation is ongoing and future appraisal drilling will be conducted.

In Blocks 144 & 145, the Company acquired 2D seismic in 2013 and undertook seabed surveys in 2015 and 2016. The Company has sought an extension to complete the remaining seismic commitment.

Total proved reserves for Lac Da Vang (Golden Camel) field development in Vietnam at December 31, 2024 were approximately 12.0 million BBL of liquids and 2.8 billion cubic feet of natural gas.

Côte d’Ivoire

During the second quarter of 2023, Murphy signed PSCs as operator for five deepwater blocks in the Tano Basin offshore Côte d’Ivoire, Africa. The five blocks have a total area of 1.5 million gross acres, with Murphy holding a 90% working interest in four blocks and an 85% working interest in the fifth block. Société Nationale d’Opérations Pétrolières de la Côte d’Ivoire holds the remaining working interest for each block.

Commitments for the initial exploration periods across the five blocks consist of seismic reprocessing. Block CI-103 includes the Paon discovery, appraised with multiple wells by a previous operator. The PSC for this block also includes a commitment to submit a field development plan for this discovery by the end of 2025.

Proved Reserves

Total proved reserves for crude oil, natural gas and NGLs as of December 31, 2024 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	**218.9**	**164.1**	**21.9**	**196.8**
Onshore	104.9	68.3	15.1	128.9
Offshore [1]	114.0	95.8	6.8	67.9
Canada	**217.1**	**20.4**	**2.2**	**1,167.2**
Onshore	200.6	6.2	2.2	1,153.2
Offshore	16.5	14.2	—	14.0
Other	**0.2**	**0.2**	**—**	**0.2**
Total proved developed reserves	**436.2**	**184.7**	**24.1**	**1,364.2**
Proved Undeveloped Reserves:				
United States	**88.5**	**61.1**	**12.2**	**92.1**
Onshore	63.7	43.2	9.5	66.8
Offshore [2]	24.8	17.9	2.7	25.3
Canada	**191.8**	**17.3**	**2.3**	**1,032.7**
Onshore	185.2	10.7	2.3	1,032.7
Offshore	6.6	6.6	—	—
Other	**12.5**	**12.0**	**—**	**2.8**
Total proved undeveloped reserves	**292.8**	**90.4**	**14.5**	**1,127.6**
Total proved reserves [3]	**729.0**	**275.1**	**38.6**	**2,491.8**

[1] Includes proved developed reserves of 14.4 million barrels of oil equivalent (MMBOE), consisting of 13.2 million barrels (MMBBL) of oil, 0.5 MMBBL of NGLs and 4.2 billion cubic feet (BCF) of natural gas, attributable to the noncontrolling interest in MP GOM.

[2] Includes proved undeveloped reserves of 1.5 MMBOE, consisting of 1.3 MMBBL of oil, 0.1 MMBBL of NGLs and 0.8 BCF of natural gas, attributable to the noncontrolling interest in MP GOM.

[3] Includes proved reserves of 15.9 MMBOE, consisting of 14.5 MMBBL of oil, 0.6 MMBBL of NGLs and 5 BCF of natural gas, attributable to the noncontrolling interest in MP GOM.

[4] Includes proved natural gas reserves to be consumed in operations as fuel of 67.9 BCF, 36.0 BCF and 2.8 BCF for the U.S., Canada and Other, respectively, with 1.1 BCF of this attributable to the noncontrolling interest in MP GOM.

Murphy Oil’s 2024 total proved reserves and proved undeveloped reserves are reconciled from 2023 as presented in the table below:

(*Millions of oil equivalent barrels*) [1]	Total Proved Reserves	Total Proved Undeveloped Reserves
Beginning of year	739.5	314.0
Revisions of previous estimates	14.3	11.5
Extensions and discoveries	31.4	30.1
Improved recovery	11.3	—
Conversions to proved developed reserves	—	(62.8)
Production	(67.5)	—
End of year [2]	**729.0**	**292.8**

[1] For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of oil using a ratio of six thousand cubic feet (MCF) of natural gas to one barrel of oil.

[2] Includes 15.9 MMBOE and 1.5 MMBOE for total proved and proved undeveloped reserves, respectively, attributable to the noncontrolling interest in MP GOM.

Production of 67.5 MMBOE was not fully offset by extensions of 10.5 MMBOE in the Eagle Ford Shale, 12.1 MMBOE in Canada Onshore, 5.5 MMBOE in the Gulf of America, and 3.3 MMBOE in Canada Offshore as well as performance and price related increases of 6.3 MMBOE in Canada, 7.0 MMBOE in the Eagle Ford Shale and 12.5 MMBOE in the Gulf of America.

Murphy’s total proved undeveloped reserves at December 31, 2024 decreased 21.2 MMBOE from a year earlier. The proved undeveloped reserves reported in the table as extensions and discoveries during 2024 were predominantly attributable to four areas: the Gulf of America, the Eagle Ford Shale in South Texas, Tupper Montney in Onshore Canada and Offshore Canada. The U.S. and Canadian assets had active development work ongoing during the year and new drilling locations were sanctioned in the Gulf of America. The majority of proved undeveloped reserves associated with revisions of previous estimates was the result of performance adjustments in Tupper Montney and the Eagle Ford Shale and positive price revisions in Tupper Montney from decreased royalty rates and decelerated royalty incentive payouts arising from lower commodity prices. The majority of the proved undeveloped reserves migration to the proved developed category are attributable to drilling in Tupper Montney, the Gulf of America, and the Eagle Ford Shale. Other proved undeveloped increases resulted from sanctioned development plans for the non-operated Zephyrus field.

The Company spent approximately $670 million in 2024 to convert proved undeveloped reserves to proved developed reserves. In the next three years, the Company expects to spend a range of approximately $650 million to $800 million per year to move current undeveloped proved reserves to the developed category. The anticipated level of spending in 2025 primarily includes drilling and development in the Gulf of America, Eagle Ford Shale, Tupper Montney, Kaybob and Vietnam areas.

At December 31, 2024, proved reserves are included for several development projects, including oil developments in the Eagle Ford Shale in South Texas, Gulf of America, Kaybob Duvernay in Canada Onshore and Lac Da Vang (Golden Camel) in Vietnam; as well as natural gas developments in Tupper Montney in Canada Onshore. Total proved undeveloped reserves associated with various development projects at December 31, 2024 were approximately 292.8 MMBOE, which represents 40% 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. Projects in deepwater fields in the Gulf of America and Canada Offshore include five undeveloped locations that exceed this five-year window. Total reserves associated with the five locations amount to less than 1% of the Company’s total proved reserves at year-end 2024. 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 or behind-pipe completions with significant capital costs that categorize them as undeveloped.

Murphy Oil's Reserves Processes and Policies

All estimates of reserves are made in compliance with SEC Rule 4-10 of Regulation S-X, which states that "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, from known reservoirs, and under existing economic conditions, operating methods, and government regulations." 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 gas reporting. Crude oil, natural gas and NGLs reserve estimates are developed or reviewed by Qualified Reserves Estimators (QREs). QREs are technical professionals embedded within the asset teams. QRE qualification generally 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. Larger business units of the Company also employ Regional Reserves Coordinators who coordinate and provide oversight of the reserve submissions to senior management and the Corporate Reserves group. Murphy provides annual training to all Company reserves estimators to ensure SEC requirements associated with reserves estimation and Form 10-K reporting are fulfilled.

Proved reserves are consolidated and reported through the Corporate Reserves group. Murphy's General Manager Corporate Reserves (Reserves General Manager) leads the Corporate Reserves group that also includes Corporate Reserve engineers and support staff, all of which are independent of the Company's oil and natural gas operational management and technical personnel. The Reserves General Manager joined Murphy in 2020 and has more than 32 years of industry experience. He has a Bachelor of Science in Mechanical Engineering and is also a licensed Professional Engineer in the State of Texas. The Reserves General Manager reports to the Executive Vice President and Chief Financial Officer and makes annual presentations to the Board 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 comply with the rules and regulations of the SEC.

The Reserves General Manager coordinates and oversees the third-party audits which are performed annually. In 2024, third party audits were conducted for proved reserves covering 71.6% of total proved reserves. All audits conducted during this period were within the established +/- 10.0% tolerance.

Ryder Scott Company ("Ryder Scott") performed audits for certain reserve estimates of Murphy's U.S. fields as of December 31, 2024. The Ryder Scott summary report is filed as an exhibit to this Annual Report on Form 10-K. The team lead for Ryder Scott has over 22 years of industry experience, joining Ryder Scott over 19 years ago. He is a registered Professional Engineer in the State of Texas.

McDaniel & Associates ("McDaniel") performed audits for certain reserve estimates of our Canadian fields as of December 31, 2024. The McDaniel summary report is filed as an exhibit to this Annual Report on Form 10-K. The two technical advisors for McDaniel both have over 18 years of experience in the estimation and evaluation of reserves with McDaniel. Both are registered Professional Engineers with the Association of Professional Engineers and Geoscientists of Alberta.

Netherland, Sewell & Associates, Inc. ("NSAI") performed audits for certain reserve estimates of our Gulf of America fields as of December 31, 2024. The NSAI summary report is filed as an exhibit to this Annual Report on Form 10-K. The team lead for NSAI has over 20 years of industry experience, joining NSAI over 15 years ago.

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 and NGLs for the last three years are presented by geographic area on pages 108 through 115 of this Form 10-K report. 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 SEC. Annually, Murphy reports gross reserves of properties operated in the U.S. 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 and NGLs production and sales, and natural gas sales by geographic area with weighted average sales prices for each of the three years ended December 31, 2024 are shown on page 34 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 37 of this Form 10-K report.

Supplemental disclosures relating to oil and natural gas producing activities are reported on pages 106 through 121 of this Form 10-K report.

Acreage and Well Count

At December 31, 2024, 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	111	97	22	21	133	118
	Offshore	56	25	524	269	580	294
Total United States		167	122	546	290	713	412
Canada	Onshore	132	108	173	136	305	244
	Offshore	105	12	28	1	133	13
Total Canada		237	120	201	137	438	257
Brunei		2	—	—	—	2	—
Brazil		—	—	2,453	1,110	2,453	1,110
Côte d'Ivoire		—	—	1,489	1,332	1,489	1,332
Vietnam		—	—	7,324	4,571	7,324	4,571
Totals		406	242	12,013	7,440	12,419	7,682

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

Scheduled expirations in 2025 includes 1,090 thousand net acres in Côte d'Ivoire, 304 thousand net acres in Vietnam, 75 thousand net acres in Brazil, 5 thousand net acres in U.S. Offshore and 1 thousand net acres in Canada Onshore.

Acreage currently scheduled to expire in 2026 includes 4,267 thousand net acres in Vietnam, 241 thousand net acres in Côte d'Ivoire, 25 thousand net acres in U.S. Offshore, 6 thousand net acres in Canada Offshore and 1 thousand net acres in Canada Onshore.

Scheduled expirations in 2027 includes 75 thousand net acres in Brazil and 7 thousand net acres in U.S. Offshore.

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 to the depth of a stratigraphic horizon known to be productive.

The following table shows the number of oil and natural gas wells producing or capable of producing at December 31, 2024:

		Oil Wells		Natural Gas Wells	
		Gross	Net	Gross	Net
United States	Onshore	1,221	971	30	5
	Offshore	81	37	13	5
Total United States		1,302	1,008	43	10
Canada	Onshore	19	13	356	340
	Offshore	50	5	—	—
Total Canada		69	18	356	340
Totals		1,371	1,026	399	350

Murphy’s net wells drilled and completed in the last three years are shown in the following table:

	United States		Canada		Other		Totals	
	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry
2024								
Exploration	**0.3**	**0.8**	**—**	**—**	**—**	**—**	**0.3**	**0.8**
Development	**23.9**	**—**	**15.3**	**—**	**—**	**—**	**39.2**	**—**
2023								
Exploration	—	1.3	—	—	—	—	—	1.3
Development	34.1	—	15.1	—	—	—	49.2	—
2022								
Exploration	—	—	—	—	—	0.6	—	0.6
Development	29.1	—	22.1	—	—	—	51.2	—

Murphy’s drilling wells in progress at December 31, 2024 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
United States	Onshore	—	—	22.0	11.2	22.0	11.2
	Offshore	—	—	1.0	0.3	1.0	0.3
Canada	Onshore	—	—	5.0	5.0	5.0	5.0
	Offshore	—	—	—	—	—	—
Other		—	—	1.0	0.4	1.0	0.4
Totals		—	—	29.0	16.9	29.0	16.9

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 and 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 Scope 1 and 2 GHG emissions and are 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 reduction goals for our operated assets. The Company has established a Scope 1 and 2 GHG emissions intensity reduction target of 15% to 20% by 2030 from our 2019 level, excluding our discontinued and divested Malaysia operations. In addition, we have endorsed the goal of eliminating routine flaring by 2030, under the current World Bank definition of routine flaring.

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 2024 Sustainability Report, located on the Company's website, for details, which is not incorporated by reference hereto.

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 liabilities, without regard to fault or legality of the conduct, on current and past owners or operators of a site where a 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 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 of 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. 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 America 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 America, 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 U.S. Outer Continental Shelf, including the Gulf of America. 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 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 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 America and onshore in South Texas and from its Canadian onshore business in British Columbia and Alberta. In Canada, Murphy is subject to GHG regulations and resultant carbon pricing programs specific to the jurisdiction of operation. Any limitations or further regulation of GHG, such as a cap and trade system, technology mandate, emissions tax, or expanded reporting requirements, could cause the Company to restrict operations, curtail demand for hydrocarbons generally, and/or cause costs to increase. Examples of cost increases include costs to operate and maintain facilities, install pollution emission controls and administer and manage emissions trading programs.

On March 8, 2024, the EPA published its final rules imposing new and stricter requirements for methane monitoring, reporting, and emissions control at certain oil and natural gas facilities. Further, the EPA amended its GHG Reporting Rule on May 14, 2024 to modify certain calculation methodologies, changes to the general reporting structure, and EPA's treatment of advanced measurement technologies. Ultimately, both new rules will impact how much reporters owe under the new methane waste emissions charge (WEC) established under the Inflation Reduction Act (IRA) in 2022 and finalized in November 2024.

In January 2025, however, President Trump signed a series of executive orders that call upon the EPA to submit a report on the continuing applicability of its endangerment finding for GHGs under the Clean Air Act, direct federal executive departments and agencies to initiate a regulatory freeze for certain rules that have not taken effect, pending review by the newly appointed agency head, direct federal agencies to identify and exercise emergency authorities to facilitate conventional energy production, transportation, and refining, and mandate a review of existing regulations that may burden domestic energy development. The methane WEC's relationship to the IRA also means that the methane WEC's implementation may be subject to further acts of the U.S. Congress. Thus, the future of the new methane and waste emission charge rules, as well as the regulation of GHGs by the U.S. federal government, may be subject to change in the near-term.

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, 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.

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 Occupational Health and Safety Legislation, the provincially-administered Occupational Health and Safety Act (Alberta), the Workers Compensation Act (British Columbia) and the Workplace Hazardous Materials Information System.

Environmental, Social and Governance (ESG) Disclosure

Our annual sustainability report is informed by internationally recognized ESG reporting frameworks and standards, including Sustainability Accounting Standards Board, Task Force on Climate-related Financial Disclosures (TCFD), Global Reporting Initiative, Ipieca and American Petroleum Institute.

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 2024, we published our sixth annual sustainability report, located on the Company's website, which is not incorporated by reference hereto.

Human Capital Management

At Murphy, we believe in providing energy that empowers people, and that is what our 750 employees do every day. As of December 31, 2024, we had 482 office-based employees and 268 field employees, all of whom are guided by our mission, vision, values and behaviors. Together with the Executive Leadership Team, the Vice President, Human Resources and Administration, who reports directly to our President and Chief Executive Officer (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
- Health and Welfare Benefits
- Employee Engagement

The Board receives related updates from the Vice President, Human Resources and Administration on a regular basis including the review of compensation, benefits, succession and talent development.

Employee Compensation Programs

Our purpose, to provide energy that empowers people, includes tying a portion of our employees' pay to performance in a variety of ways, including incentive compensation and performance-based bonus programs, while maintaining the best interest of stockholders. We benchmark for market practices and regularly review our compensation and hiring acceptance rates against the market to ensure competitiveness to attract and retain the best talent. We believe our current practices align our employees' compensation with the interests of our stockholders and support our focus on cash flow generation, capital return and environmental stewardship. To enhance employee understanding of their total remuneration package extended by Murphy, we introduced Total Reward Statements for employees in the U.S., Canada and Vietnam. For further details 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 14, 2025.

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 the 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; and
- Maintain a process that is consistent throughout the organization to measure employee performance that is tied to the Company's and stockholders' 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 contributions toward executing our Company's goals and business strategy.

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. Through our digital platform, My Murphy Learning, employees have access to LinkedIn Learning with more than 10,600 courses, Continuing Education Unit credit and certification opportunities, and access to expert instructors. We also administer mandatory compliance training for our employees through My Murphy Learning with 100% utilization. Finally, 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.

To enhance employees' commitment to and understanding of the Company's Scorecard, we introduced a training course entitled, *Understanding Your Annual Incentive Plan*, which covers all metrics in our scorecard. This training opportunity, in particular, enhanced the business acumen of our employee base, as well as brought renewed focus to how we measure success.

We strive to empower our leadership with programs that offer career advancement for experienced and emerging leaders. In 2024, over 50 managers participated in a leadership program, from a top-rated institution, addressing focus areas such as strategic agility, decision making, building high-performing teams and enhancing trust. Furthermore, we implemented a refreshed and expanded Technical Career Map to enhance the development of 125 engineering and geoscience employees.

We encourage employee engagement and solicit feedback through internal surveys, focus groups and our employee-led 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 monitor the effectiveness of our human capital investment and development programs, 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 2024, our voluntary employee turnover rate, including retirements, was 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 of Murphy's success. As such, we provide our employees and their families with a comprehensive set of subsidized benefits that are competitive and aligned with Murphy's mission, vision, values and behaviors. We also believe that the well-being of our employees is enhanced when they can give back to their local communities or charities through programs like the Company Matching Gift Program, the "Impact – Murphy Makes a Difference" Program, or on their own with a Company match for donations.

Finally, we offer an Employee Assistance Program 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.

Employee Engagement

At Murphy, we strive for excellence in our people and our work. We believe that having employees who reflect a broad range of backgrounds, experiences and perspectives contributes to a more productive, engaged workforce and a more enriching environment for everyone. This belief underlies Murphy's commitment to fostering an inclusive workplace where the most talented want to work and where our employees understand our culture of belonging. In furtherance of that commitment, Murphy, through its policies and its actions, requires strict compliance with all anti-harassment and anti-discrimination laws and does not tolerate harassment or discrimination of any kind based on any protected characteristic.

The Board receives updates on employee composition and recruiting, hiring, promotion, and retention of employees from the Vice President, Human Resources and Administration on a regular cadence. As of December 31, 2024, our U.S. and international workforce was comprised of approximately 24% females, and our U.S. workforce was comprised of approximately 33% of minority groups (as defined by the U.S. Equal Employment Opportunity Commission).

We also support interest-based groups such as sports, hobbies, and charity volunteering in our communities. In 2024, we increased the number of employee-led, self-directed Employee Resource Groups with the introduction of ASPIRE (Asian and Pacific Islander Women) and VIPER (Veteran Integration and Purpose). Participation is voluntary, with membership and programming open to all Murphy employees.

Website Access to SEC Reports

Murphy Oil's internet 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 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 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 and NGLs 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:

- worldwide and domestic supplies of, and demand for, crude oil, natural gas and NGLs;
- the ability of the members of the Organization of the Petroleum Exporting Countries (OPEC) and certain non-OPEC members, for example, Russia, to agree to maintain or adjust production levels;
- the production levels of non-OPEC countries, including, amongst others, production levels in the shale plays in the U.S.;
- political instability or armed conflict in oil and natural gas producing regions, such as the Russia-Ukraine conflict and Israeli-Palestinian conflict;
- the level of drilling, completion and production activities by other exploration and production companies, and variability therein, in response to market conditions;
- changes in weather patterns and climate, including those that may result from climate change;

- natural disasters such as hurricanes and tornadoes, including those that may result from 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 natural gas exploration, development, and production activities and considerations including climate change and the transition to a lower carbon economy;
- the occurrence or threat of epidemics or pandemics, such as the outbreak of COVID-19, or any government response to such occurrence or threat which may lower the demand for hydrocarbon fuels;
- domestic and foreign governmental regulations, taxes and other actions, including tariffs, economic sanctions and further legislation requiring, subsidizing or providing tax benefits for the use or generation of alternative energy sources and fuels; and
- general economic conditions worldwide, including inflationary conditions and related governmental policies and interventions.

West Texas Intermediate (WTI) crude oil prices averaged $75.72 per BBL in 2024, compared to $77.62 in 2023 and $94.23 in 2022. 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 Mars, WTI Houston (MEH), Heavy Louisiana Sweet (HLS) and Brent.

The average New York Mercantile Exchange (NYMEX) natural gas sales price was $2.24 per million British Thermal Units (MMBTU) in 2024, compared to $2.53 in 2023 and $6.38 in 2022. The Company also has exposure to the Canadian benchmark natural gas price, Alberta Energy Company (AECO), which averaged C$1.46 per MCF in 2024, compared to C$2.64 in 2023 and C$5.31 in 2022. The Company has entered into certain forward fixed price contracts as detailed in the "Outlook" section beginning on page 51 and spot contracts providing exposure to other market prices at specific sales points such as Malin (Oregon, U.S.) and Dawn (Ontario, Canada).

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.

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.
- Lower oil and natural gas prices could lead to an inability to access, renew, or replace credit facilities, and could also impair access to other sources of funding as these mature, potentially negatively impacting our liquidity.

- Lower prices for oil and natural gas could cause the Company to lower its dividend because of lower cash flows.

See Note K 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. To the extent that the Company enters into these contracts and in the event that prices for oil and natural gas increase in future periods, the Company will not fully benefit from the price improvement on all production. See Note K 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, 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 subject its exploration and production operating results to exposure to dry hole expense, which has in the past, and may in the future, adversely affect our results of operations. The Company plans to continue assessing exploration activities as part of its overall strategy. In 2024, the Company participated in four exploration wells. The Hai Su Vang-1X (Golden Sea Lion), Block 15/2-17 exploration well, located in offshore Vietnam, and the non-operated Ocotillo #1 (Mississippi Canyon 40) exploration well, located in the Gulf of America, resulted in commercial discoveries while the Sebastian #1 (Mississippi Canyon 387) and non-operated Orange #1 (Mississippi Canyon 216) wells, located in the Gulf of America, did not encounter commercial hydrocarbons. Additionally, the Company expensed previously suspended costs associated with the Hoffe Park #1 (Mississippi Canyon 166) well which was determined to be non-commercial. The Company has budgeted $145 million for its 2025 exploration program, which includes drilling two wells in Vietnam, two wells in the Gulf of America, and one well in Côte d'Ivoire.

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 must find, acquire or develop, and produce 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 and NGLs included in this report on pages 106 through 115 have been prepared according to the SEC guidelines by qualified company personnel or qualified independent engineers based on an unweighted average of crude oil, natural gas and NGL 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, natural gas and NGL 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 2024, 71.6% 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, 2024, and including noncontrolling interests, approximately 33% of the Company's crude oil proved reserves, 38% of NGL proved reserves and 45% 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 119 and 120 should not be considered as the market value of the reserves attributable to our properties. As required by U.S. 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 reliant on certain third party infrastructure to develop projects and operations.

The Company relies on the availability and capacity of infrastructure, such as transportation and processing facilities, and equipment that are often owned and operated by others. These third-party systems, facilities, and equipment may not always be available to the Company and, if available, may not be available at a price that is acceptable to the Company. The unavailability or high cost of such equipment or infrastructure could adversely affect our ability to establish and execute exploration and development plans within budget and on a timely basis, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our inability to access appropriate equipment and infrastructure in a timely manner and on acceptable terms may hinder our access to oil and natural gas markets or delay our oil and natural gas production.

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 2024, approximately 21% of the Company's total production was at fields operated by others, while at December 31, 2024, approximately 14% of the Company's total proved reserves were at fields operated by others.

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 prices, 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 operator's or partners' cash flows or ability to obtain adequate financing, or if an operator of our projects fails to adequately perform operations or fulfill its obligations under the applicable agreements, 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, severe weather events, 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 a variety of locales, including urban, 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, tropical storms and extreme temperatures. Many of the Company's offshore fields are in the Gulf of America, where hurricanes and tropical storms can lead to shutdowns and damages. The U.S. hurricane season runs from June through November. Moreover, scientists have predicted that increasing concentrations of GHG in the earth's atmosphere may produce climate changes that increase significant weather events, such as increased frequency and severity of storms, droughts, 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, due to policy deductibles and possible coverage limits, weather-related risks to our operations are not fully insured. In addition, the physical effects of climate change may generally result in reduced availability of relevant insurance coverage on the market. For additional details on insurance, see "Risk Factors - General Risk Factors – 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."

In addition, certain customer and supplier assets, such as storage terminals, processing facilities, refineries and pipelines, are located in areas that may be prone to severe weather events, including hurricanes, winter storms, floods and major tropical storms, all of which may be exacerbated by climate change. Severe weather events that significantly affect facilities belonging to such customers or suppliers may reduce demand for our products and interrupt our ability to bring products to market and may therefore materially and adversely affect our results of operations, cash flows and financial condition, even if our own facilities escape significant damage.

Hydraulic fracturing operations subject the Company to operational risks inherent in the drilling and production of oil and natural gas.

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 risks associated with hydraulic fracturing operations include, but are not limited to, 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 due to regulatory initiatives or natural constraints such as drought or otherwise result in operational delays or increased costs.

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, regulations, governmental actions and permit requirements, 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 methane and other GHG emissions; wildlife, habitat and water protection; water access, use and disposal; the placement, operation and decommissioning of production equipment; the health and safety of our employees, contractors and communities where our operations are located, including indigenous communities; and the causes and impacts of climate change. The laws, regulations, governmental actions and permit requirements are subject to frequent change and have tended to become stricter over time and at times may be motivated by political considerations. 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. For example, in March 2024, the U.S. EPA published its final rule regulating methane and volatile organic compounds emissions in the oil and gas industry which, among other things, requires periodic inspections to detect leaks (and subsequent repairs), places stringent restrictions on venting and flaring of methane, and establishes a program whereby third parties can monitor and report large methane emissions to the U.S. EPA. In November 2024, the U.S. EPA published its final rule implementing a charge on large emitters of waste methane from the oil and gas sector. The charge, referred to as the WEC, is a component of the Biden Administration's Methane Emissions Reduction Program to limit methane emissions from the oil and gas industry under the IRA of 2022. In addition, it is possible in the future that certain regulatory bodies such as the Railroad Commission of Texas may enact regulation that bans or reduces flaring for U.S. Onshore operations, and certain regulatory bodies in Canada may decide to revoke permits or pause the issuance of permits as a result of non-compliance with, or litigation related to, environmental, health and safety laws and regulations. Compliance with such regulations could result in capital investment or operating costs which would reduce the Company's net cash flows and profitability.

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.

The Company primarily uses hydraulic fracturing in the Eagle Ford Shale in South Texas and in Kaybob Duvernay and Tupper Montney 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.

In addition, the BOEM and the 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 America, 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 America, 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 U.S. Outer Continental Shelf. 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 Biden 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 the Interior's overhaul of permitting and leasing regulations and rates, finalized in April 2024, could adversely impact Murphy's operations. These developments demonstrate the uncertainty regarding the regulation of oil and natural gas related to shifts in political power in the U.S. For further details, 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 natural gas exploration, development, and production activities and sustainability considerations, including climate change and the transition to a lower carbon economy.

Opposition toward oil and natural gas drilling, development, and production activity has been growing globally. Companies in the oil and natural gas industry are often the target of activist efforts from both individuals and nongovernmental 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 or onshore hydraulic fracking.

Activism may continue to increase regardless of the U.S. Administration's environmental and climate change executive orders described earlier in this Form 10-K report. Our need to incur costs associated with responding to these initiatives or complying with any new legal 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 natural gas industry could result in a reduction in the demand for our products or otherwise affect our results of operations or financial condition.

We may face increased scrutiny from investors and other stakeholders related to our sustainability activities, including the goals, targets and objectives we announce, our methodologies and timelines for pursuing them and related disclosures. If our sustainability practices do not meet investor or other stakeholder expectations and standards, which continue to evolve, our reputation, our ability to attract or retain employees and our attractiveness as an investment or business partner could be negatively affected. Similarly, our failure or perceived failure to pursue or fulfill our sustainability-focused goals, targets and objectives, to comply with ethical, environmental or other standards, regulations or expectations or to satisfy various reporting standards with respect to these matters, within the timelines we announce, or at all, could adversely affect our business or reputation, as well as expose us to government enforcement actions and private litigation.

While the Company has been named a co-defendant with other oil and natural gas companies in lawsuits related to climate change, these lawsuits have not resulted in, and are not currently expected to result in, material liability for the Company. Depending on the evolution of laws, regulations and litigation outcomes relating to climate change, there can be no guarantee that climate change litigation will not in the future materially adversely affect our results of operations, cash flows and financial condition. For further details on risks related to legal proceedings more generally, see "Risk Factors - General Risk Factors - Lawsuits against Murphy and its subsidiaries could adversely affect its operating results."

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. During the fourth quarter of 2024, the Company entered into a credit agreement governing a $1.35 billion revolving credit facility (RCF). The RCF is a senior unsecured guaranteed facility and will expire in October 2029. As of December 31, 2024, the Company had no outstanding borrowings under the RCF. See Note F for further details on the RCF.

The Company's ability to obtain additional financing is affected by a number of factors, including the market environment, our operating and financial performance, investor sentiment, our ability to incur additional debt in compliance with agreements governing our outstanding debt, and the Company's credit ratings. 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 any additional indebtedness we incur, and potentially require the Company to post additional letters of credit or other forms of collateral for certain obligations. Murphy partially manages this risk through borrowing at fixed rates wherever possible; however, rates when refinancing or raising new capital are determined by factors outside of the Company's control.

Further, changes in investors' sentiment or view of risk of the exploration and production industry, including as a result of concerns over climate change, could adversely impact the availability of future financing. Specifically, certain financial institutions (including certain investment advisors and sovereign wealth, pension and endowment funds), in response to concerns related to climate change and the requests and other influence of environmental groups and similar stakeholders, have elected to shift some or all of their investments away from fossil fuel-related sectors, and additional financial institutions and other investors may elect to do likewise in the future. As a result, fewer financial institutions and other investors may be willing to invest in, and provide capital to, companies in the oil and natural gas sector, which, in turn, could adversely impact our cost of capital.

Since 2022, the Company undertook several actions to reduce overall debt. Murphy plans to continue with the Company's deleveraging initiatives, but there can be no assurance that these efforts will be successful and, if not, the Company's financial conditions and prospects could be adversely affected. See Note F for information regarding the Company's outstanding debt as of December 31, 2024.

We may be unable to meet our capital allocation framework of returning a percentage of adjusted free cash flow to shareholders through share repurchases and potential dividend increases, which could decrease expected returns on an investment in our common stock.

Our capital allocation framework includes returning a percentage of adjusted free cash flow to shareholders through share repurchases and potential dividend increases. We may, from time to time, redeem, repurchase, retire or otherwise acquire our outstanding debt through privately negotiated transactions, open market purchases, redemptions, tender offers or otherwise, but we are under no obligation to do so. There can be no assurance that we will seek to do any of the foregoing or that we will be able to do any of the foregoing on terms acceptable to us or at all.

In connection with our capital allocation framework, the Board authorized a share repurchase program, as described in this Form 10-K report. Share repurchases and dividends are authorized and determined by the Board at its sole discretion and depend upon a number of factors, including available liquidity, market conditions, applicable legal requirements and other factors. We can provide no assurance that we will make share repurchases or pay dividends in accordance with our capital allocation framework, or at all. Any elimination of, or downward revision in, our share repurchase program, dividend payment plans, or capital allocation framework could have an adverse effect on the market price of our common stock.

Meeting our capital allocation framework strategy requires us to generate consistent adjusted free cash flow and have available capital in the years ahead in an amount sufficient to enable us to maintain a conservative capital structure and liquidity position and invest in organic and inorganic growth, as well as to return a significant portion of the cash generated to shareholders through share repurchases and potential dividend increases. The amount of adjusted free cash flow returned in any quarter during the year may vary and may be more or less than our capital allocation framework. We may not meet this goal if we use our available cash to satisfy other priorities, if we have insufficient funds available to repurchase shares or pay dividends, or if the Board determines to change or discontinue share repurchases or dividend payments.

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. The Company operates in various regions around the world which inherently introduces exposure to changes in foreign exchange rates when transacting in local currencies. See also Note K 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 addition, periods of inflationary pressure in the wider economy, as seen during 2022, can also lead to a similar increase in the cost of goods and services for the Company. Murphy has a dedicated 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 the 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 principal 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 that 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.

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.

The future impact of any health epidemic, pandemic (such as COVID-19) or similar outbreak cannot be predicted, and any resurgence of disease may cause additional volatility in commodity prices. See "Risk Factors - Price Risk Factors – Volatility in the global prices of crude oil, natural gas and NGLs 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 an epidemic, pandemic or similar outbreak, our operations will likely be impacted and our ability to produce oil, natural gas and NGLs will likely decrease. We may be unable to perform fully on our commitments, and our costs may increase as a result of such epidemic, pandemic or similar outbreak. These cost increases may not be fully recoverable or adequately covered by insurance.

In addition, an epidemic, pandemic or similar outbreak 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 cannot predict the impact of an epidemic, pandemic or similar outbreak. The extent to which any such epidemics, pandemics or similar outbreaks 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.

Changes in U.S. and international tax rules and regulations, or interpretations thereof, may materially and adversely affect our cash flows, results of operations and financial condition.

We are subject to income- and non-income-based taxes in the U.S. under federal, state and local jurisdictions and in the foreign jurisdictions in which we operate. Tax laws and regulations, or their interpretation, and administrative practices in various jurisdictions may be subject to significant change, with or without advance notice, due to economic, political and other conditions, and significant judgment is required in evaluating and estimating our provision and accruals for these taxes. Our tax liabilities could be affected by numerous factors, such as changes in tax, accounting and other laws, regulations, administrative practices, principles and interpretations, the mix and level of earnings in a given taxing jurisdiction or our ownership or capital structure. In recent years, multiple domestic and international tax proposals have been introduced that, if enacted into law would impose greater tax burdens on certain multinational enterprises. For example, the Organization for Economic Co-operation and Development (OECD) continues to advance proposals or guidance in international taxation, including the establishment of model rules for a new 15% global minimum tax on certain multinational enterprises, also known as Pillar Two. Many countries have implemented or are in the process of implementing these model rules. While we do not currently expect that Pillar Two will have a material impact on our results of operations, we continue to monitor the impact as countries implement legislation and the OECD provides additional guidance. In addition, the IRA, enacted in the U.S. on August 16, 2022, imposes several new taxes that were effective in 2023, including, but not limited to, a 15% corporate book minimum tax for taxpayers with adjusted financial statement income exceeding an average of $1 billion over a three-year testing period and a 1% excise tax on certain stock repurchases made after December 31, 2022. We continue to analyze the potential impact of the IRA on our consolidated financial statements and to monitor guidance issued by the U.S. Department of the Treasury. It is possible that further changes may be enacted to U.S. and international tax rules and regulations, including the U.S. corporate tax system, which could have a material effect on our consolidated cash taxes in the future.

We face continued competition for talent to support our operations.

The success of our operations is dependent upon our ability to hire, develop, and retain qualified and experienced personnel. The oil and natural gas industry has experienced increased merger and acquisition activity, causing Murphy and industry peers to face heightened competition from other industries for highly sought after and transferable skill sets. In addition, changes in public sentiment towards oil and natural gas exploration, development, and production activities, along with considerations such as climate change and the transition to a lower carbon economy, may make it more difficult for us to attract such qualified personnel.

Due to significant shifts in demographics impacting the industry, such as an aging workforce and decreased enrollment in relevant fields, Murphy and industry peers are experiencing challenges in sourcing and developing a pipeline of talent for the foreseeable future, which could place our oil and natural gas exploration, development, and production activities at risk. Furthermore, the cost to attract and retain technical talent has increased in recent years due to competition and may continue to increase if the pool of available talent continues to shrink due to these demographic shifts. If there is a significant decrease in the availability of qualified talent, our operations, cash flows, and financial condition may be materially and adversely impacted.

Murphy's sensitive information, operational technology systems and critical data 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 data and preventing breaches is critical to our business operation. We rely on our information systems, and our cybersecurity training and policies, to protect and secure intellectual property, strategic plans, customer information, and personally identifiable information of both our employees and our customers.

A digital infrastructure failure or a successfully executed, undetected cyberattack could significantly disrupt business operations. For example, it might lead to downtime, revenue loss, diversion of management or work force attention, and increased costs for remediation. Additionally, the compromise, theft, or unauthorized release of critical data could damage our reputation, weaken our competitive edge, negatively impact our financial stability and expose us to legal risk in multiple jurisdictions. Due to the nature of cyberattacks, breaches to our systems could go undetected for a prolonged period of time. Nevertheless, even if we successfully defend our own digital infrastructure, we also rely on our customers and suppliers, with whom we may share data and services, to protect their digital infrastructure and services from cybersecurity incidents.

As the sophistication of cyber threats continues to evolve, including through the use of artificial intelligence, we may be required to dedicate additional resources to continue to modify or enhance our security measures, or to investigate and remediate any discovered vulnerabilities to cyberattacks. In addition, laws and regulations governing, or proposed to govern, cybersecurity, data privacy and protection and the unauthorized disclosure of confidential or protected information, including legislation in domestic and international jurisdictions, pose increasingly complex compliance challenges and potentially elevate costs, and any failure to comply with these laws and regulations could result in significant penalties and legal liability. Additionally, new regulations or legislation may affect our current uses of protected information and require us to modify how we collect, protect, process or disclose such information.

We are incorporating artificial intelligence technologies into our processes and these technologies may present business, compliance, and reputational risks.

Our business increasingly utilizes artificial intelligence ("AI"), machine learning, and automated decision making to improve our internal processes. Issues in the development and use of AI, combined with an uncertain regulatory environment, may result in new or enhanced governmental or regulatory scrutiny, litigation, confidentiality or security risks, reputational harm, liability or other adverse consequences to our business operations, all of which could adversely affect our business, financial condition and results of operations.

The use of AI can lead to unintended consequences, including the unauthorized use or disclosure of confidential and proprietary information, or generating content that appears correct but is factually inaccurate, misleading, or otherwise flawed, which could expose us to risks related to inaccuracies or errors in the output of such technologies. It is not possible to predict all of the risks related to the use of AI, machine learning and automated decision making, and developments in the regulatory frameworks governing the use of such technologies and in related stakeholder expectations may adversely affect our ability to develop and use such technologies or subject us to liability.

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 policy makers, regulators or other parties to delay or deny necessary licenses and permits to produce or transport crude oil and natural gas. As an example, the Biden Administration pursued initiatives related to environmental, health and safety standards applicable to the oil and natural gas industry. These included 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 natural 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 implementation of the pause in new federal oil and natural 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. In August 2022, the IRA of 2022 was passed by the U.S. Congress and included provisions which required the Department of Interior to hold previously announced offshore lease sales in the Gulf of America and Alaska within two years. However, on December 14, 2023, the Secretary of the Interior approved the 2024-2029 National Outer Continental Shelf Oil and Gas Leasing Program, which contemplates only three potential oil and natural gas lease sales in the Gulf of America through 2029. These developments demonstrate the uncertainty that can arise from the U.S. Administration's approach to oil and natural gas leasing and permitting.

In March 2024, the SEC adopted rules requiring disclosure of a wide range of climate change-related information, including, among other things, companies' climate change risk management; short-, medium-, and long-term climate-related financial risks; and disclosure of Scope 1 and Scope 2 emissions. Similar laws and regulations regarding climate change-related disclosures have been proposed or enacted in other jurisdictions, including California and the European Union. The SEC's climate disclosure rules have been stayed pending legal challenges, but implementation of the rules as finalized could be costly and time consuming. On February 11, 2025, the SEC notified the U.S. Court of Appeals of a statement issued by the SEC's Acting Chairman regarding, among other things, the fact that the majority of current SEC Commissioners had previously voted against adopting the rules, and requested that the U.S. Court of Appeals not schedule the case for argument to provide time for the SEC to deliberate and determine the appropriate next steps in the cases.

These actions and any future changes to applicable environmental, health and safety, regulatory and legal requirements promulgated by the U.S. Administration and Congress may restrict our access to additional acreage and new leases in the Gulf of America 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 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 law changes, royalty increases, redefinition of international boundaries, preferential and discriminatory awarding of oil and natural gas leases, restrictions on drilling and/or production, tariffs, restraints and controls on imports and exports, safety, and relationships between employers and employees. For example, the Trump Administration has proposed additional tariffs on Canada and Mexico. Such tariffs may put upwards pressure on the prices of goods and services across the jurisdictions in which we operate, which could reduce our ability to offer competitive pricing to potential customers. We cannot predict what changes to trade policy will be made by the Trump Administration, the U.S. Congress or other governments, including whether existing tariff policies will be maintained or modified or whether the entry into new bilateral or multilateral trade agreements will occur, nor can we predict the effects that any such changes would have on our business. Changes in trade policy have resulted and could again result in reactions from trading partners, including adopting responsive trade policies making it more difficult or costly for us to conduct business across the jurisdictions in which we operate. Such changes in trade policy or in laws and policies governing foreign trade, and any resulting negative sentiments as a result of such changes, could materially and adversely affect our business, financial condition, results of operations and liquidity. 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, 2024, 1.7% 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 GHGs 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, including the U.S. Administration, 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 a limit of $450 million per occurrence ($850 million for Gulf of America 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.

Murphy's business model may come under more pressure from changing environmental and social trends and the related global demands for non-fossil fuel energy sources. This demand in alternative forms of energy may cause the price of our products to become more volatile and decline. Further, a reduction in demand for fossil fuels could adversely impact the availability of future financing. As part of Murphy's strategy review process, the Company reviews hydrocarbon demand forecasts and assesses the impact on its business model, plans and future estimates of reserves. In addition, the Company evaluates other lower-carbon technologies that could complement our existing assets, strategy and competencies as part of its long-term capital allocation strategy. The Company also has significant natural gas reserves which emit lower carbon compared to crude oil and NGLs.

The issue of climate change has caused considerable attention to be directed towards initiatives to reduce global GHG emissions. International agreements such as the Paris Agreement and subsequent yearly "conferences of the parties" 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 to calls for transitioning away from fossil fuels and a pledge to achieve near-zero methane emissions by a specified future date. In addition, presidential administrations could issue various executive orders that may result in additional laws, rules and regulations in the area of climate change.

It is possible that international agreements, presidential executive orders, and other such initiatives, including foreign, federal, and state laws, rules, or regulations related to GHG 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 efforts that aim to subsidize the development of non-fossil fuel energy sources, may reduce the competitiveness of carbon-based fuels, such as oil and natural 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 global climate change initiatives and plans accordingly based on its assessment of the effects 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, environmental and/or property damages, climate change 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 SEC as of December 31, 2024.

Item 1C. CYBERSECURITY

Murphy's cybersecurity environment and risk strategy is broadly managed by the Company's Information Technology (IT) group, which oversees the Company's IT and Operational Technology (OT) infrastructure. Within the IT group, the Murphy Cybersecurity Team (MCT) is specifically responsible for monitoring and managing security of the enterprise IT and OT network and systems, including developing and deploying administrative policies, technical controls, and safety protocols necessary to prevent unauthorized access, theft, damage, or loss of Company data or systems. All members of the MCT hold globally-recognized security certifications and have wide-ranging experience in cybersecurity matters. The Incident Management Team (IMT) is responsible for responding to active security threats and incidents as they occur. The Chief Information Officer oversees the IT group and is a member of the IMT, and provides briefings to the CEO, the executive leadership team, and the Audit Committee of the Board regarding cybersecurity risks, strategy, and management at least annually. The Audit Committee is ultimately responsible for overseeing cybersecurity strategy and ensuring that management has sufficient resources, programs, and processes in place to identify, evaluate, manage, and mitigate relevant cybersecurity risks to which Murphy is exposed and to implement processes and programs to manage cybersecurity risks and mitigate any incidents. The Audit Committee also reports material cybersecurity risks to the Board as appropriate. We believe this visibility and oversight structure allows the Board and executive leadership team to make timely, data-driven decisions ensuring that Murphy, its employees, investors, and partners are adequately protected.

Murphy considers its cybersecurity risk management framework to be a core component of its overall enterprise risk management system. The cybersecurity risk management framework directly aligns with the National Institute of Standards and Technology Cybersecurity Framework and involves regular review and update of security policies and procedures; leverage of industry-leading technologies focused on continuously monitoring, analyzing, and defending against intrusions; regular testing of such technologies and other controls; periodic simulations of security incidents; and constant monitoring of the broader cybersecurity environment for new and emerging threats. The Company also requires employees to attend regular cybersecurity training and education to mitigate cybersecurity risks. To remain informed of the cybersecurity landscape, the Company collaborates with peers, third-party advisors, industry groups and policymakers.

Murphy engages cybersecurity assessors, consultants, our internal auditors, and other third parties both periodically and as appropriate when cyber threats are identified. Murphy utilizes these consultants to perform forensic analysis of data published by threat actors, to monitor and scan Murphy's systems for threat vectors, and to consult on emerging cybersecurity environment topics.

In addition to monitoring its own IT systems, Murphy also has processes in place to identify cybersecurity risks and threats associated with third party service providers and partners. These processes include conducting vendor due diligence and risk assessments, participating in industry information sharing groups, subscribing to cybersecurity notification services, and maintaining ongoing collaboration with federal agencies.

To our knowledge, Murphy has not experienced any cybersecurity incidents that have had, or are likely to have, material impacts to our business, operations, finances, or reputation.

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 Natural Gas Information” section of this Annual Report on Form 10-K on pages 106 to 121 and in Note D beginning on page 77.

Item 3. LEGAL PROCEEDINGS

Discussion of the Company’s legal proceedings are included in Note Q beginning on page 98.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Information about our Executive Officers

The present corporate office, length of service in office, and age at February 1, 2025, for 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.

Eric M. Hambly – Age 50; President and Chief Executive Officer since January 2025. Mr. Hambly served as President and Chief Operating Officer from February 2024 to December 2024. Mr. Hambly also served as Executive Vice President, Operations from 2020 to 2024 and Executive Vice President, Onshore from 2018 to 2020.

Thomas J. Mireles – Age 52; Executive Vice President and Chief Financial Officer since 2022. Mr. Mireles was Senior Vice President, Technical Services from 2018 to 2022. Mr. Mireles also served as the Senior Vice President, Eastern Hemisphere of Murphy Exploration & Production Company from 2016 to 2018.

E. Ted Botner – Age 60; Executive Vice President, General Counsel and Corporate Secretary since February 2024. Mr. Botner served as Senior Vice President, General Counsel and Corporate Secretary from 2020 to 2024. He also served as Vice President, Law and Corporate Secretary from 2015 to 2020 and Manager, Law and Corporate Secretary from 2013 to 2015.

Daniel R. Hanchera - Age 67; Senior Vice President, Business Development since 2022. Mr. Hanchera served as Senior Vice President, Business Development of Murphy Exploration & Production Company from 2014 to 2022. He also served as Vice President, Business Development and Planning of Murphy Exploration & Production Company from 2009 to 2014.

John B. Gardner – Age 56; Vice President, Marketing and Supply Chain since 2022. Mr. Gardner was Vice President and Treasurer from 2015 to 2022 and served as Treasurer from 2013 to 2015.

Leyster L. Jumawan - Age 48; Vice President, Corporate Planning and Treasurer since 2022. Mr. Jumawan was Assistant Treasurer from 2017 to 2022.

Maria A. Martinez – Age 50; Vice President, Human Resources and Administration since 2018. Ms. Martinez was Vice President, Human Resources of Murphy Exploration & Production Company from 2013 to 2018.

Meenambigai Palanivelu - Age 51; Vice President, Sustainability since 2023. Ms. Palanivelu was Director, Sustainability from 2020 to 2023. Ms. Palanivelu also served as the General Manager, Planning and Performance from 2019 to 2020 and General Manager, Finance Operating Model Program Management Office from 2017 to 2019.

Louis W. Utsch – Age 59; Vice President, Tax since 2018.

Paul D. Vaughan – Age 58, Vice President and Controller since 2022. Mr. Vaughan was Vice President and Controller, U.S., Central and South America of Murphy Exploration & Production Company from 2017 to 2022.

Kelly L. Whitley – Age 59; 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 1,873 stockholders of record as of December 31, 2024. Information on dividends per share by quarter for 2024 and 2023 are reported on page 122 of this Form 10-K report. Dividends are authorized and determined by the Board at its sole discretion and depend upon a number of factors, including available liquidity, market conditions, applicable legal requirements and other factors.

Issuer Purchases of Equity Securities

The Board has authorized a share repurchase program whereby the Company can repurchase up to $1,100.0 million of its common stock. Pursuant to the share repurchase program, the Company may repurchase shares through open market purchases, privately negotiated transactions and other means in accordance with federal securities laws. This repurchase program has no time limit and may be suspended or discontinued completely at any time without prior notice as determined by the Company at its discretion and dependent upon a variety of factors.

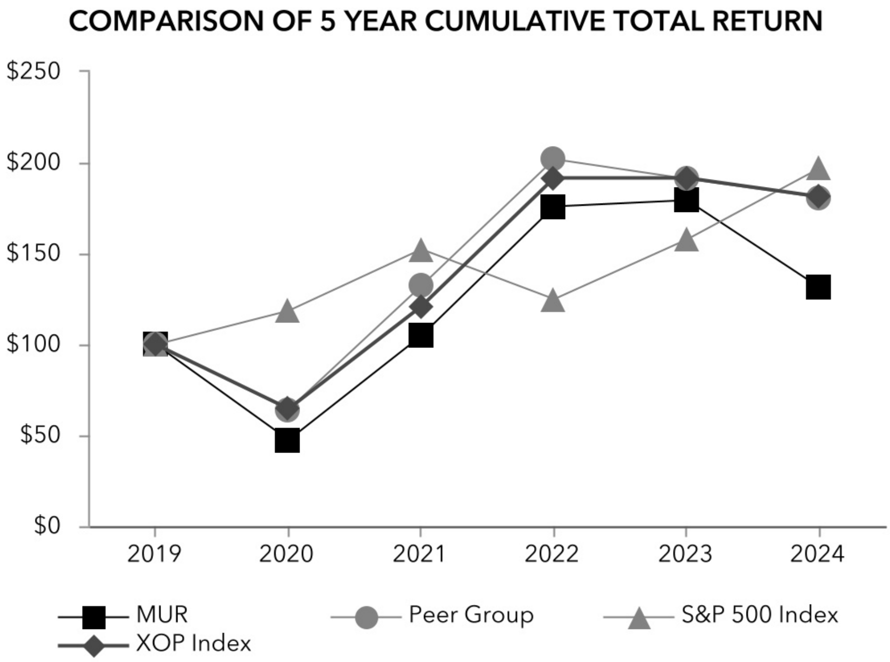
During the three months ended December 31, 2024, the Company did not repurchase any shares of its common stock. Since the inception of the share repurchase program through the end of the fourth quarter of 2024, the Company has repurchased 11.4 million shares of its common stock in open-market transactions. As of December 31, 2024, the Company had $650.1 million of its common stock remaining available to repurchase under the program.

Subsequent to year end, as of February 25, 2025, the Company repurchased 3.4 million shares of its common stock in open-market transactions for $95.1 million, excluding taxes and fees. As of this date, the Company had $555.0 million of its common stock remaining available to repurchase under the program.

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, 2019 in the Company, the Standard & Poor's 500 Stock Index (S&P 500 Index), the S&P Oil & Gas Exploration & Production Select Industry Index (XOP Index) and the Company's peer group. XOP Index reports a comprehensive view of the oil and natural 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. Our peer group for 2024 is presented in the table below. Civitas Resources Inc., EOG Resources Inc. and Magnolia Oil & Gas Corporation were added to Murphy's peer group in 2024. Callon Petroleum Company, Hess Corporation and PDC Energy Inc. were removed from Murphy's peer group in 2024. 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 include:

APA Corporation	Kosmos Energy Ltd.	Range Resources Corporation
Civitas Resources Inc.	Magnolia Oil & Gas Corporation	SM Energy Company
Coterra Energy Inc.	Marathon Oil Corporation [1]	Southwestern Energy Company [1]
Devon Energy Corporation	Matador Resources Company	Talos Energy Inc.
EOG Resources Inc.	Ovintiv Inc.	



	2019	2020	2021	2022	2023	2024
Murphy Oil Corporation	100	47	104	176	179	131
Peer Group	100	64	132	201	191	180
S&P 500 Index	100	118	152	125	158	197
XOP Index	100	65	121	192	192	181

[1] Marathon Oil Corporation and Southwestern Energy Company were acquired in 2024 and therefore have been excluded from the above table and graph of cumulative total return.

Item 6. RESERVED

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

The following Management’s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) should be read together with the consolidated financial statements and accompanying notes to consolidated financial statements, which are included in Item 8 of this Annual Report on Form 10-K. This MD&A includes forward-looking statements that involve certain risks and uncertainties. See “Forward-Looking Statements” at the end of this section and “Risk Factors” under Item 1A. Discussion and analysis of 2022 results and year-over-year comparisons between 2023 and 2022 are not included in this Form 10-K and can be found in “Item 7” of the 2023 Annual Report on Form 10-K available via the SEC’s website at www.sec.gov and on our website at www.murphyoilcorp.com.

Murphy Oil Corporation is a worldwide oil and natural gas exploration and production company with both onshore and offshore operations and properties. The Company produces crude oil, natural gas and NGLs primarily in the U.S. and Canada and explores for crude oil, natural gas and NGLs in targeted areas worldwide. A more detailed description of the Company’s significant assets can be found in “Item 1” of this Form 10-K report.

The analysis and discussion in this section includes amounts attributable to a noncontrolling interest (NCI) in MP GOM, unless otherwise noted.

Significant Company financial and operational highlights during 2024 were as follows:

- Generated net income of $486.5 million ($407.2 million excluding NCI and net cash provided by operating activities of $1,729.0 million;
- Produced 184 thousand BOEPD (177 thousand BOEPD excluding NCI);
- Issued $600.0 million of 6.000% senior notes due 2032, and used proceeds to redeem an aggregate $600.0 million of senior notes due 2027, 2028 and 2029;
- Entered into a new five-year, $1.35 billion senior unsecured credit facility, representing a 69% increase from previous facility size;
- Advances made under the capital allocation framework[1]:
    - Repurchased $50.0 million of long-term debt;
    - Repurchased 8.0 million shares of common stock under the share repurchase program for $300.0 million ($302.7 million including excise taxes and fees);
- Achieved 84% (83% excluding NCI) total proved reserve replacement with year-end proved reserves of 729.0 million MMBOE (713.1 MMBOE excluding NCI);
- Drilled an oil discovery at Hai Su Vang-1X (Golden Sea Lion) in offshore Vietnam and encountered approximately 370 feet of net oil pay from two reservoirs; and
- Drilled a discovery at the non-operated Ocotillo #1 exploration well in Mississippi Canyon 40 in the Gulf of America and found 100 feet of net pay across two zones.

[1] Details of the capital allocation framework can be found as part of the Company’s Form 8-K filed on August 4, 2022 and Form 8-K filed on August 8, 2024. The Company’s Board of Directors has authorized a share repurchase program whereby the Company can repurchase up to $1,100.0 million of the Company’s common stock.

Murphy’s continuing operations generate revenue by producing crude oil, natural gas and NGLs in the U.S. and Canada and then selling these products to customers. The Company’s revenue is affected by the prices of crude oil, natural gas and NGLs. 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 capital borrowing from lending institutions and note holders.

For the year ended December 31, 2024, the Company’s net income from continuing operations was $489.3 million, a decrease of $235.9 million compared to 2023. Lower net income from continuing operations was largely driven by lower revenues and other income ($431.7 million), higher lease operating expenses ($152.7 million), and higher impairment expense ($62.9 million), partially offset by lower income tax expense ($117.6 million), lower exploration expenses ($101.2 million), higher other income ($79.5 million), lower other operating expense ($35.5 million) and lower transportation, gathering and processing costs ($22.2 million). Lower revenues from production were primarily driven by mechanical and weather downtime in the Gulf of America, timing and performance of new wells at Eagle Ford Shale and lower average oil and natural gas prices, partially offset by wells brought back online at the non-operated Terra Nova field in the fourth quarter of 2023. Higher lease operating expenses were primarily due to workovers in the Gulf of America and higher production activity in Canada at the Terra Nova field, partially offset by lower production handling fees in the Gulf of America. Higher impairment expense is due to impairment of the Calliope and Nearly Headless Nick fields in the Gulf of America. The decrease in income tax expense is primarily driven by lower overall income, in addition to an income tax deduction for prior years’ Australia exploration spend. Exploration expenses in the current period was primarily due to dry hole expense recorded for multiple wells in the Gulf of America, including Sebastian #1 (Mississippi Canyon 387), non-operated Orange #1 (Mississippi Canyon 216), and for previously suspended exploration costs related to an expired lease at Hoffe Park #1 (Mississippi Canyon 166). Higher other income related to unrealized foreign exchange gains and interest income on several outstanding joint interest receivables. Lower other operating expense in 2024 is primarily driven by lower non-operated Terra Nova field start-up costs, contingency adjustments and asset retirement obligations (ARO) revisions. Lower interest expense was due to lower debt levels. Lower transportation, gathering and processing expenses related to lower production in the U.S.

For the year ended December 31, 2024, total hydrocarbon production was 184,293 BOEPD, a decrease of 4% compared to 2023. The decrease was principally due to lower production in the U.S., primarily in the Gulf of America due to downtime for wells awaiting workovers and in the Eagle Ford Shale due to timing and performance of new wells and partially offset by the restart of production at the non-operated Terra Nova field in Canada in the first quarter of 2024.

Results of Operations

Murphy’s Net income (loss) by type of business and geographic segment is presented below:

(Millions of dollars)	**2024**	2023	2022
Exploration and production			
United States	**$ 561.9**	$ 905.1	$ 1,521.9
Canada	**49.0**	41.6	134.2
Other International	**(12.5)**	(65.5)	(77.0)
Total exploration and production	**598.4**	881.2	1,579.1
Corporate and other	**(109.1)**	(156.0)	(438.3)
Income from continuing operations	**489.3**	725.2	1,140.8
Loss from discontinued operations [1]	**(2.8)**	(1.5)	(2.1)
Net income including noncontrolling interest	**486.5**	723.7	1,138.7
Net income attributable to noncontrolling interest	**79.3**	62.1	173.7
Net income attributable to Murphy	**$ 407.2**	$ 661.6	$ 965.0

[1] The Company has presented its former U.K., Malaysia and U.S. refining and marketing operations as discontinued operations in its consolidated financial statements.

E&P Continuing Operations: 2024 vs 2023

The following section of Exploration and Production (E&P) continuing operations excludes the Corporate segment, unless otherwise noted.

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

The following is a summarized statement of operations for E&P continuing operations:

(Millions of dollars)	**2024**	2023	2022
Revenues and other income			
Revenue from production	**$ 3,014.9**	$ 3,376.6	$ 4,038.5
Sales of purchased natural gas	**3.7**	72.2	181.7
Other income	**6.0**	8.0	26.7
Total revenues and other income	**3,024.6**	3,456.8	4,246.9
Costs and Expenses			
Lease operating expenses	**937.0**	784.4	679.3
Severance and ad valorem taxes	**39.2**	42.8	57.0
Transportation, gathering and processing	**210.8**	233.0	212.7
Costs of purchased natural gas	**3.1**	51.7	172.0
Depreciation, depletion and amortization	**856.9**	850.5	763.9
Impairments of assets	**62.9**	—	—
Accretion of asset retirement obligations	**52.4**	46.0	46.2
Total exploration expenses, including undeveloped lease amortization	**133.5**	234.8	133.1
Selling and general expenses	**23.8**	37.7	44.5
Other	**0.3**	56.9	141.8
Results of operations before taxes	**704.7**	1,119.0	1,996.4
Income tax provisions	**106.3**	237.8	417.3
Results of operations (excluding Corporate segment) [1]	**$ 598.4**	$ 881.2	$ 1,579.1

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

Pricing

The following table contains the weighted average sales prices for the three years ended December 31, 2024:

(Weighted average sales prices)	**2024**	2023	2022
Crude oil and condensate – dollars per barrel			
United States - Onshore	**$ 75.77**	$ 76.96	$ 96.00
United States - Offshore [1]	**76.36**	77.38	94.21
Canada - Onshore [2]	**67.49**	72.84	89.88
Canada - Offshore [2]	**82.22**	84.20	107.47
Other [2]	**77.59**	86.60	94.37
Natural gas liquids – dollars per barrel			
United States - Onshore	**20.20**	19.69	33.85
United States - Offshore [1]	**23.37**	21.94	36.01
Canada - Onshore [2]	**34.14**	35.87	55.65
Natural gas – dollars per thousand cubic feet			
United States - Onshore	**1.90**	2.26	6.04
United States - Offshore [1]	**2.40**	2.78	6.97
Canada - Onshore [2]	**1.59**	2.06	2.76

[1] Prices include the effect of noncontrolling interest in MP GOM.
[2] U.S. dollar equivalent.

PART II

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Continued

The following table contains benchmark prices relevant to the Company for the three years ended December 31, 2024:

(Average price for the period)	**2024**	2023	2022
Oil and NGLs			
WTI ($/BBL)	**$ 75.72**	$ 77.62	$ 94.23
Natural gas			
NYMEX ($/MMBTU)	**2.24**	2.53	6.38
AECO (C$/MCF)	**1.46**	2.64	5.31

Production Volumes

The following table contains hydrocarbons produced during the three years ended December 31, 2024. For further discussion on volumes, please see “Revenues from Production” section on page 37.

(Barrels per day unless otherwise noted)	**2024**	2023	2022
Net crude oil and condensate			
United States - Onshore	**21,151**	24,070	24,437
United States - Offshore [1]	**63,047**	73,473	65,411
Canada - Onshore	**2,868**	2,937	4,005
Canada - Offshore	**7,251**	3,020	2,812
Other	**219**	250	700
Total net crude oil and condensate	**94,536**	103,750	97,365
Net natural gas liquids			
United States - Onshore	**4,442**	4,617	5,181
United States - Offshore [1]	**4,544**	5,924	4,597
Canada - Onshore	**597**	681	903
Total net natural gas liquids	**9,583**	11,222	10,681
Net natural gas – thousands of cubic feet per day			
United States - Onshore	**25,028**	25,863	29,050
United States - Offshore [1]	**57,228**	70,239	63,380
Canada - Onshore	**398,786**	369,906	310,230
Total net natural gas	**481,042**	466,008	402,660
Total net hydrocarbons - including NCI [2,3]	**184,293**	192,640	175,156
Noncontrolling interest			
Net crude oil and condensate – barrels per day	**(6,358)**	(6,210)	(7,452)
Net natural gas liquids – barrels per day	**(199)**	(220)	(280)
Net natural gas – thousands of cubic feet per day	**(1,942)**	(2,089)	(2,468)
Total noncontrolling interest [2,3]	**(6,881)**	(6,778)	(8,143)
Total net hydrocarbons - excluding NCI [2,3]	**177,412**	185,862	167,013
Estimated total proved net hydrocarbon reserves - million equivalent barrels [3,4]	**729.0**	739.5	715.4

[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, 2024, 2023 and 2022, include 15.9 MMBOE, 15.5 MMBOE and 18.2 MMBOE, respectively, relating to noncontrolling interest.

Sales Volumes

The following table contains hydrocarbons sold during the three years ended December 31, 2024. For further discussion on volumes, please see "Revenues from Production" section on page 37.

(Barrels per day unless otherwise noted)	**2024**	2023	2022
Net crude oil and condensate			
United States - Onshore	**21,151**	24,070	24,437
United States - Offshore [1]	**63,612**	73,373	64,840
Canada - Onshore	**2,868**	2,937	4,005
Canada - Offshore	**6,445**	2,559	3,002
Other	**230**	349	663
Total net crude oil and condensate	**94,306**	103,288	96,947
Net natural gas liquids			
United States - Onshore	**4,443**	4,617	5,181
United States - Offshore [1]	**4,543**	5,924	4,597
Canada - Onshore	**597**	681	903
Total net natural gas liquids	**9,583**	11,222	10,681
Net natural gas – thousands of cubic feet per day			
United States - Onshore	**25,028**	25,863	29,050
United States - Offshore [1]	**57,228**	70,239	63,380
Canada - Onshore	**398,786**	369,906	310,230
Total net natural gas	**481,042**	466,008	402,660
Total net hydrocarbons - including NCI [2,3]	**184,063**	192,178	174,738
Noncontrolling interest			
Net crude oil and condensate – barrels per day	**(6,438)**	(6,200)	(7,369)
Net natural gas liquids – barrels per day	**(198)**	(220)	(280)
Net natural gas – thousands of cubic feet per day	**(1,942)**	(2,089)	(2,468)
Total noncontrolling interest [2,3]	**(6,960)**	(6,768)	(8,060)
Total net hydrocarbons - excluding NCI [2,3]	**177,103**	185,410	166,678

[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.

Revenues from Production

The Company's production revenues by country and product were as follows:

(Millions of dollars)	**2024**	2023	2022
Revenues from production			
United States - Oil	**$ 2,364.3**	$ 2,748.5	$ 3,085.9
United States - Natural gas liquids	**71.7**	80.6	124.4
United States - Natural gas	**67.8**	92.7	225.3
Canada - Oil	**264.8**	156.7	249.2
Canada - Natural gas liquids	**7.4**	8.9	18.3
Canada - Natural Gas	**232.3**	278.2	312.6
Other - Oil	**6.6**	11.0	22.8
Total revenues from production	**$ 3,014.9**	$ 3,376.6	$ 4,038.5

Revenues from production in 2024 decreased by $361.7 million compared to 2023. Revenue was lower in the Gulf of America, mostly driven by downtime for workovers, hurricane-related downtime and timing of new wells. Eagle Ford Shale revenues decreased due to timing and performance of wells brought online. These decreases were partially offset by wells brought back online in the fourth quarter of 2023 at non-operated Terra Nova. Lower pricing across all products also contributed to the decrease during the period.

Natural gas is purchased and subsequently sold to third parties in order to provide operational flexibility and cost mitigation for transportation commitments. "Sales of purchased natural gas" is included in "Total revenues and other income" and "Costs of purchased natural gas" is included in "Costs and Expenses" in the summarized statement of operations for E&P continuing operations on page 33. Sales of purchased natural gas during 2024 were $3.7 million.

Lease Operating and Transportation, Gathering and Processing Expenses

The Company's total lease operating expenses and transportation, gathering and processing expenses by geographic area were as follows:

	(Millions of dollars)			*(Dollars per equivalent barrel)*		
	2024	2023	2022	**2024**	2023	2022
Lease operating expenses						
United States – Onshore	**$ 141.9**	$ 150.3	$ 137.6	**$ 13.02**	$ 12.48	$ 10.94
United States – Offshore	**608.0**	480.4	385.1	**21.38**	14.46	13.19
Canada – Onshore	**132.6**	140.3	139.5	**5.18**	5.89	6.75
Canada – Offshore	**52.9**	11.5	15.6	**22.43**	12.30	14.20
Other	**1.6**	1.9	1.5	**18.52**	14.94	6.25
Total lease operating expenses	**$ 937.0**	$ 784.4	$ 679.3	**$ 13.91**	$ 11.18	$ 10.65
Transportation, gathering and processing						
United States – Onshore	**$ 9.6**	$ 12.7	$ 18.4	**$ 0.88**	$ 1.05	$ 1.47
United States – Offshore	**121.3**	144.3	123.8	**4.27**	4.34	4.24
Canada – Onshore	**75.5**	72.2	65.3	**2.95**	3.03	3.16
Canada – Offshore	**4.4**	3.8	5.2	**1.85**	4.12	4.76
Total transportation, gathering and processing	**$ 210.8**	$ 233.0	$ 212.7	**$ 3.13**	$ 3.32	$ 3.34

Lease operating expenses and transportation, gathering and processing expenses in 2024 increased by $152.6 million and decreased by $22.2 million, respectively, compared to 2023. Higher lease operating expenses were primarily due to workover costs in the Gulf of America, particularly at the Samurai and Neidermeyer fields, and the restart of the non-operated Terra Nova field in Canada Offshore in the first quarter of 2024. These were partially offset by lower production handling fees and lower overall volumes. Lower transportation, gathering and processing expenses were primarily due to lower volumes.

Depreciation, Depletion and Amortization Expense

The Company’s depreciation, depletion and amortization expense by geographic area was as follows:

	(Millions of dollars)			*(Dollars per equivalent barrel)*		
	2024	2023	2022	**2024**	2023	2022
Depreciation, depletion and amortization expense						
United States – Onshore	**$ 319.9**	$ 316.7	$ 321.4	**$ 29.36**	$ 26.29	$ 25.55
United States – Offshore	**389.3**	389.3	295.6	**13.69**	11.72	10.12
Canada – Onshore	**123.5**	133.4	128.1	**4.82**	5.60	6.20
Canada – Offshore	**22.5**	8.8	13.4	**9.55**	9.47	12.25
Other	**1.7**	2.3	5.4	**20.13**	18.05	22.19
Total depreciation, depletion and amortization expense	**$ 856.9**	$ 850.5	$ 763.9	**$ 12.72**	$ 12.12	$ 11.98

Depreciation, depletion and amortization expense (DD&A) in 2024 increased by $6.4 million compared to 2023. Higher DD&A was primarily the result of higher volumes at the non-operated Terra Nova field in Canada Offshore and higher rates at Eagle Ford Shale and in the Gulf of America, and was partially offset by lower volumes in the Gulf of America and lower rates and volumes at Kaybob Duvernay.

Impairment of Assets

In 2024 the Company recorded impairment costs for two assets in the Gulf of America, totaling $62.9 million. In the first quarter of 2024, the Company recognized an impairment expense of $34.5 million for the Calliope field. In the fourth quarter of 2024, an impairment expense of $28.4 million was recorded for the Nearly Headless Nick field. Both fields were impaired as a result of operational issues that led to reserve reductions.

There were no impairments recorded in 2023.

Exploration Expenses

The Company’s exploration expenses were as follows:

(Millions of dollars)	**2024**	2023	2022
Exploration expenses			
Dry holes and previously suspended exploration costs	**$ 73.2**	$ 169.8	$ 82.1
Geological and geophysical	**27.2**	26.1	10.4
Other exploration	**23.5**	28.0	27.3
Undeveloped lease amortization	**9.6**	10.9	13.3
Total exploration expenses	**$ 133.5**	$ 234.8	$ 133.1

Exploration expenses in 2024 decreased by $101.3 million compared to 2023. In 2024, dry holes and previously suspended exploration costs primarily related to the Sebastian #1 (Mississippi Canyon 387) exploration well, the non-operated Orange #1 (Mississippi Canyon 216) exploration well, and the previously suspended exploration well at Hoffe Park #1 (Mississippi Canyon 166) in the Gulf of America. In 2023, dry holes and previously suspended exploration costs related to previously suspended exploration costs for the Cholula-1EXP well in offshore Mexico and dry hole costs for the Chinook #7 (Walker Ridge 425) exploration well and the non-operated Oso #1 (Atwater Valley 138) exploration well in the Gulf of America, both of which encountered non-commercial hydrocarbons.

Other Expenses

Other expenses were $0.3 million in 2024, a decrease of $56.6 million compared to 2023. Other expenses were lower primarily due to the absence of other operating expenses in Canada related to the non-operated Terra Nova life extension project, lower asset retirement adjustments, no contingent consideration adjustments in the current period and higher interest income received in 2024.

Income Taxes

Income taxes were $106.3 million in 2024, a decrease of $131.5 million compared to 2023. Lower income taxes were primarily the result of lower pretax income, and an income tax deduction for prior years’ Australia exploration spend (see Note H).

Corporate: 2024 vs 2023

Corporate activities include interest expense and income, foreign exchange effects, realized and unrealized gains/losses on derivative instruments (forward swaps to hedge the price of oil sold) and corporate overhead not allocated to E&P. Realized and unrealized losses on derivative instruments result from increases in market oil and natural gas prices relating to future periods whereby the swap contracts provided the Company with a fixed price.

Corporate activities reported a loss of $109.1 million in 2024, a favorable variance of $46.9 million compared to 2023. The favorable variance was primarily due to foreign exchange gain of $45.4 million in 2024 compared to foreign exchange loss of $10.7 million in 2023, primarily as a result of unrealized exchange rate changes relating to our Canadian subsidiary. Interest charges are lower in 2024 primarily due to lower overall debt levels. The lower income tax benefit was the result of a lower current period loss before income tax.

Financial Condition

The Company’s primary sources of liquidity are cash on hand, net cash provided by continuing operations activities and available borrowing capacity under its senior unsecured RCF, as described below. The Company’s liquidity requirements, both in the short-term (2025) and long-term (beyond 2025), consist primarily of capital expenditures, debt maturity, retirement and interest payments, working capital requirements, dividend payments, and, as applicable, share repurchases. The Company may, from time to time, redeem, repurchase or otherwise acquire its outstanding notes through open market purchases, tender offers or pursuant to the terms of such securities. The Company believes that the primary sources of liquidity described above will be adequate to fund its liquidity needs over the next 12 months.

Cash Flows

The following table presents the Company’s cash flows for the periods presented.

(Millions of dollars)	**2024**	2023	2022
Net cash provided by (required by):			
Net cash provided by continuing operations activities	**$ 1,729.0**	$ 1,748.8	$ 2,180.2
Net cash required by investing activities	**(908.2)**	(998.7)	(1,109.4)
Net cash required by financing activities	**(716.5)**	(923.7)	(1,081.6)
Net cash required by discontinued operations	**—**	—	(14.5)
Effect of exchange rate changes on cash and cash equivalents	**2.2**	(1.2)	(3.9)
Net (decrease) increase in cash and cash equivalents	**$ 106.5**	$ (174.8)	$ (29.2)

Cash Provided by Continuing Operations Activities

Net cash provided by continuing operations activities in 2024 was $19.8 million lower compared to 2023. The decrease was primarily attributable to lower revenue from production ($361.7 million) and higher lease operating expenses costs ($152.6 million), partially offset by a decrease due to timing of non-cash working capital ($174.2 million) settlements, no contingent consideration payments related to prior Gulf of America acquisitions in 2024 (2023: $139.6 million), lower exploration expenses ($101.2 million), and changes in other operating activities, net ($56.4 million) primarily due to decreased expenditures for asset retirements.

Payments of contingent consideration in 2023 are shown both in "Operating Activities" and "Financing Activities" in the Company's Consolidated Statements of Cash Flows; amounts considered as financing activities are those amounts paid up to the original estimated contingent consideration liability included in the purchase price allocation, at the time of acquisition. Any contingent consideration paid above the original estimated liability, included in the purchase price, are considered operating activities.

During 2023, the Company paid a total of $199.8 million in contingent consideration, of which $139.6 million is shown in "Operating Activities" and $60.2 million is shown in "Financing Activities" in the Company's Consolidated Statements of Cash Flows. As of the end of the second quarter of 2023, the Company had no further obligation payable for contingent consideration relating to prior Gulf of America acquisitions. See Note O for further details.

The total reductions of operating cash flows for interest paid (which excludes "Early redemption of debt cost" reported in "Financing Activities") during the two years ended December 31, 2024, and 2023 were $78.8 million and $108.9 million, respectively. Cash interest paid in 2024 was primarily due to interest payments on outstanding debt. Some of these payments related to accelerated interest payments due to the early redemption, in part, of the 5.875% senior notes due 2027 (2027 Notes), the 6.375% senior notes due 2028 (2028 Notes), and the 7.05% senior notes due 2029 (2029 Notes) in the aggregate redemption amount of $650.1 million. In 2023, cash interest paid was higher than 2024, primarily due to higher debt levels in 2023 and accelerated interest payments due to the early redemption, in whole or in part, of the 5.75% senior notes due 2025 (2025 Notes), the 2027 Notes, the 2028 Notes, and the 2029 Notes for an aggregate redemption amount of $498.2 million.

Cash Required by Investing Activities

Net cash required by investing activities in 2024 was $90.5 million lower compared to 2023. The decrease was primarily due to lower property additions and dry hole costs ($157.9 million) and lower acquisition capital ($35.6 million), partially offset by the absence of proceeds from the sale of certain non-core operated Kaybob Duvernay assets and all of the non-operated Placid Montney assets ($102.9 million).

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

	Year Ended December 31,		
(Millions of dollars)	**2024**	2023	2022
Property additions and dry hole costs per cash flow statements	**$ 908.2**	$ 1,066.0	$ 985.5
Geophysical and other exploration expenses	**44.8**	46.0	30.6
Acquisition of oil and natural gas properties per the cash flow statements	**—**	35.6	128.5
Capital expenditure accrual changes and other	**11.8**	(9.5)	38.6
Total capital expenditures	**$ 964.8**	$ 1,138.1	$ 1,183.2

Total accrual basis capital expenditures are shown below.

	Year Ended December 31,		
(Millions of dollars)	**2024**	2023	2022
Capital Expenditures			
Exploration and production	**$ 935.7**	$ 1,114.0	$ 1,161.5
Corporate	**29.1**	24.1	21.7
Total capital expenditures	**964.8**	1,138.1	1,183.2
Total capital expenditures excluding proved property acquisitions	**964.8**	1,111.0	1,054.7
Total capital expenditures excluding proved property acquisitions and NCI	**$ 952.8**	$ 1,040.8	$ 1,028.8

Lower capital expenditures in 2024 compared to 2023 were primarily attributable to lower development expenditures at Eagle Ford Shale, Tupper Montney, and non-operated Terra Nova and lower exploration expenses in the Gulf of America, partially offset by higher exploration and development costs in offshore Vietnam.

Capital expenditures in 2024 primarily relate to development drilling and field development activities in the Gulf of America, primarily related to the Mormont, Khaleesi, Lucius, St. Malo and Samurai fields ($306.9 million), at Eagle Ford Shale ($291.8 million), at Tupper Montney and Kaybob Duvernay ($116.3 million), at other international locations ($45.1 million), and at non-operated Hibernia ($18.2 million). In addition, total exploration costs were $153.9 million.

Exploration costs in 2024 were primarily comprised of activities in the Gulf of America related to the Sebastian #1 (Mississippi Canyon 387), Orange #1 (Mississippi Canyon 216), and non-operated Oso #1 (Atwater Valley 138) exploration wells. Sebastian #1 and Orange #1 encountered non-commercial hydrocarbons during 2024. Non-operated Oso #1 encountered non-commercial hydrocarbons in 2023, and operations completed in 2024. Additional exploratory costs relate to oil discoveries, including the non-operated Ocotillo #1 (Mississippi Canyon 40) exploration well in the Gulf of America and the Hai Su Vang-1X (Golden Sea Lion), Block 15/2-17 exploration well in Vietnam, as well as other ongoing projects.

Cash Required by Financing Activities

Net cash required by financing activities in 2024 decreased by $207.2 million compared to 2023. In 2024, cash used in financing activities was principally for the repurchase of common shares ($301.4 million, excluding excise tax). In addition, the Company completed a refinancing transaction whereby new senior notes due 2032 were issued in the aggregate amount of $600.0 million and the proceeds were used for the aggregate repayment and repurchase of $600.0 million of its 2027 Notes, 2028 Notes and 2029 Notes. The Company also repurchased $50.0 million of its 2027 Notes, paid cash dividends to shareholders of $1.20 per share ($180.0 million), and distributed funds to the noncontrolling interest in MP GOM ($118.6 million).

Liquidity

At December 31, 2024, the Company had approximately $1.8 billion of liquidity consisting of $423.6 million in cash and cash equivalents and $1,349.6 million available on its committed senior unsecured RCF with a major banking consortium.

The Company's $1.35 billion senior unsecured RCF expires in October 2029. As of December 31, 2024, the Company had no outstanding borrowings under the RCF and $0.4 million of outstanding letters of credit, which reduce the borrowing capacity of the senior unsecured RCF. Borrowings under the RCF are subject to certain interest rates. Please refer to Note F for further details. At December 31, 2024, the interest rate in effect on borrowings under the facility would have been 6.68%. At December 31, 2024, the Company was in compliance with all covenants related to the RCF.

Cash and invested cash are maintained in several operating locations outside the U.S. As of December 31, 2024, cash and cash equivalents held outside the U.S. included U.S. dollar equivalents of approximately $95.2 million (2023: $149 million), the majority of which was held in Canada ($58.5 million), Vietnam ($8.7 million) and Brunei ($8.5 million). In addition, approximately $7.8 million and $6.4 million of cash was held in the U.K. and Mexico, 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 H for further information regarding potential tax expense that could be incurred upon distribution of foreign earnings back to the U.S.

Working Capital

(Millions of dollars)	**December 31, 2024**	December 31, 2023
Working capital		
Total current assets	**$ 785.3**	$ 752.2
Total current liabilities	**942.8**	846.5
Net working capital liability	**$ (157.5)**	$ (94.3)

As of December 31, 2024, net working capital had an unfavorable decrease of $63.2 million compared to December 31, 2023. The decrease was primarily attributable to lower accounts receivable ($71.5 million), higher operating lease liabilities ($45.4 million), higher current ARO liabilities ($37.4 million), and higher accounts payable ($25.3 million), partially offset by a higher cash balance ($106.5 million). Lower accounts receivable were primarily due to lower sales volumes for crude oil and natural gas, and lower pricing received for all crude oil, natural gas and NGLs. Higher operating lease liabilities are primarily due to an extension of an existing drilling ship lease in the Gulf of America. Higher current ARO liabilities are primarily due to certain Gulf of America obligations to be completed in 2025. Higher accounts payable are due to the timing of payments for certain drilling activities and ongoing workover projects.

Capital Employed

A summary of capital employed as of December 31, 2024 and 2023 follows.

	December 31, 2024		December 31, 2023	
(Millions of dollars)	**Amount**	**%**	Amount	%
Capital employed				
Long-term debt	**$ 1,274.5**	**19.7 %**	$ 1,328.4	19.9 %
Murphy shareholders' equity	**5,194.3**	**80.3 %**	5,362.8	80.1 %
Total capital employed	**$ 6,468.8**	**100.0 %**	$ 6,691.2	100.0 %

As of December 31, 2024, long-term debt decreased by $53.9 million compared to December 31, 2023, as a result of the repurchase of the 2027 Notes and 2028 Notes. The Company also completed a refinancing transaction whereby it issued $600.0 million of 2032 Notes, and used all of the proceeds to complete the repurchase and redemption, in whole or in part, of the 2027 Notes, 2028 Notes, and 2029 Notes. As of December 31, 2024, the fixed-rate notes had a weighted average maturity of 9.3 years and a weighted average coupon of 6.1%. Refer to Note F for additional details.

Murphy’s shareholders’ equity decreased by $168.5 million in 2024 primarily due to cash dividends paid ($180.0 million), shares repurchased ($302.7 million, including excise tax), and foreign currency translation losses ($134.7 million), partially offset by net income earned ($407.2 million). A summary of transactions in stockholders’ equity accounts is presented in the “Consolidated Statements of Stockholders’ Equity" on page 70 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 2024, compared to 2023 are discussed below.

Property, plant and equipment, net of depreciation decreased $170.5 million principally due to DD&A expense and foreign exchange rates applicable for the Canadian assets, substantially offset by capital expenditures in the year. Capital expenditures are discussed above in the “Cash Required by Investing Activities” section.

Murphy had commitments for capital expenditures of approximately $417.0 million at December 31, 2024 (2023: $209.8 million). This amount includes $220.0 million for Other Offshore, primarily related to approved expenditures for capital projects relating to interests in Vietnam for the Lac Da Vang (Golden Camel) field development project, $112.2 million at Eagle Ford Shale, primarily at the Karnes field, $53.6 million relating to

Gulf of America interests, primarily at the Mormont and non-operated St. Malo fields, and $31.2 million relating to interests in Canada Onshore, primarily at Kaybob Duvernay.

Operating lease assets increased $32.4 million principally due to lease extensions in the Gulf of America, partially offset by the depreciation of these assets.

Long-term ARO liabilities increased $56.8 million primarily due to accretion, additions and revisions related to Gulf of America and Eagle Ford Shale operations.

Non-current operating lease liabilities decreased $14.5 million primarily due to 2024 annual payments reducing operating lease liabilities for drilling rig and vessel commitments.

Deferred income tax liabilities increased $59.1 million due to utilization of the net operating loss, partially offset by other capital-related tax effects.

Other Key Performance Metrics

The Company uses other operational performance and income metrics to review operational performance. Management uses adjusted net income, earnings before interest, taxes, depreciation and amortization (EBITDA) and adjusted EBITDA internally to evaluate the Company's operational performance and trends between periods and relative to its industry competitors. Adjusted net income excludes certain items that management believes affects the comparability of results between periods. Management believes this information may be useful to investors and analysts to gain a better understanding of the Company's financial results. Adjusted net income, 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 GAAP.

The following table reconciles reported net income attributable to Murphy to adjusted net income from continuing operations attributable to Murphy.

	Year Ended December 31,		
(Millions of dollars)	**2024**	2023	2022
Net income attributable to Murphy (GAAP) [1]	**$ 407.2**	$ 661.6	$ 965.0
Discontinued operations loss	**2.8**	1.5	2.1
Net income from continuing operations attributable to Murphy	**410.0**	663.1	967.1
Adjustments:			
Impairment of assets	**62.9**	—	—
Write-off of previously suspended exploration well	**26.1**	17.1	22.7
Foreign exchange (gain) loss	**(45.4)**	10.9	(23.0)
Refinancing and early redemption of debt costs (non-cash)	**3.7**	—	10.3
Mark-to-market loss (gain) on derivative instruments	**1.7**	—	(214.7)
Asset retirement obligation losses	**—**	16.9	30.8
Mark-to-market loss on contingent consideration	**—**	7.1	78.3
(Gain) on sale of assets	**—**	—	(14.5)
Total adjustments, before taxes	**49.0**	52.0	(110.1)
Income tax (benefit) expense related to adjustments	**(8.3)**	(6.4)	23.8
Tax (benefit) on investments in foreign areas	**(34.0)**	—	—
Total adjustments after taxes	**6.7**	45.6	(86.3)
Adjusted net income from continuing operations attributable to Murphy (Non-GAAP)	**$ 416.7**	$ 708.7	$ 880.8
Net income from continuing operations per average diluted share (GAAP)	**$ 2.72**	$ 4.23	$ 6.14
Adjusted net income from continuing operations attributable to Murphy per average diluted share (Non-GAAP)	**$ 2.76**	$ 4.52	$ 5.59

[1] Excludes amounts attributable to a noncontrolling interest in MP GOM.

The following table reconciles reported net income attributable to Murphy to EBITDA attributable to Murphy and adjusted EBITDA attributable to Murphy.

	Year Ended December 31,		
(Millions of dollars)	**2024**	2023	2022
Net (loss) income attributable to Murphy (GAAP) [1]	**$ 407.2**	$ 661.6	$ 965.0
Income tax expense	**78.3**	195.9	309.5
Interest expense, net	**105.9**	112.4	150.8
Depreciation, depletion and amortization expense [1]	**833.1**	836.7	748.2
EBITDA attributable to Murphy (Non-GAAP)	**1,424.5**	1,806.6	2,173.5
Impairment of assets [1]	**62.9**	—	—
Accretion of asset retirement obligations [1]	**46.9**	41.0	40.9
Foreign exchange (gain) loss	**(45.4)**	10.8	(23.0)
Write-off of previously suspended exploration well	**26.1**	17.1	22.7
Discontinued operations loss	**2.8**	1.5	2.1
Mark-to-market loss (gain) on derivative instruments	**1.7**	—	(214.7)
Mark-to-market loss on contingent consideration	**—**	7.1	78.3
Asset retirement obligation losses	**—**	16.9	30.8
Gain on sale of assets [1]	**—**	—	(14.5)
Adjusted EBITDA attributable to Murphy (Non-GAAP)	**$ 1,519.5**	$ 1,901.0	$ 2,096.1

[1] Excludes amounts attributable to a noncontrolling interest in MP GOM.

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, auditing and assessments, 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, Environment and Corporate Responsibility Committee consisting of certain members of the Board.

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 methane and other 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 9.

Climate Change and Emissions

The world’s population and standard of living are growing steadily along with the demand for energy. Murphy recognizes that this may generate increasing amounts of GHG, which could 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 TCFD framework. While oversight of the TCFD framework has undergone changes, including relating to the role of the International Financial Reporting Standards Foundation in overseeing the framework, the TCFD framework continues to inform climate-related reporting practices. Murphy’s disclosures related to its alignment with the TCFD framework are included in the Company’s 2024 Sustainability Report issued on August 7, 2024, which is not incorporated by reference hereto.

Other Matters

Impact of inflation – In 2024, many countries worldwide continued to experience moderate inflation, including countries where the Company operates (this follows a sustained period of relatively low inflation prior to 2021). 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 and certain non-OPEC members’ production levels and/or attitudes of traders concerning supply and demand in the future. Costs for oil field goods and services are usually affected by the worldwide prices for crude oil.

To combat impacts of inflation and/or supply and demand factors, Murphy has dedicated personnel in marketing and procurement departments, 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 the 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 costs. Murphy continues to strive toward safely executing our work in an ever-increasingly efficient manner to mitigate possible inflationary pressures in our business.

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 is also impacted by demand for lower carbon emissions.

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 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 prices 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 ARO liabilities. 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 and NGLs are presented on pages 106 to 115 of this Form 10-K report. Murphy's estimations for proved reserves were generated through the integration of available geoscience, engineering, and economic data (including hydrocarbon prices, operating costs, and development costs), 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 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. 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, 2024 beginning on pages 4 and 106 of this Form 10-K report.

Property, Plant and Equipment - impairment of long-lived assets – The Company continually monitors its long-lived assets recorded in "Property, plant and equipment" in the Consolidated Balance Sheet to ensure that they are fairly presented. The Company must evaluate its property, plant and equipment for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable from undiscounted future net 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 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 2024, the Company recognized pretax non-cash impairment charges of $62.9 million to reduce the carrying values at select properties. In the first quarter of 2024, the Company recognized $34.5 million related to the Calliope field, in the Gulf of America, and in the fourth quarter of 2024, the Company recognized $28.4 million related to the Nearly Headless Nick field, in the Gulf of America. Both of the impairment charges were due to subsurface issues that led to reserve reductions. There were no impairments recognized in 2023.

See also Note D 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 and equipment.

The Company routinely evaluates all deferred tax assets to determine the likelihood of their realization and reduces 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, 2024 the Company had a U.S. deferred tax asset associated with net operating losses of $289.6 million. In reviewing the likelihood 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, natural gas and NGLs, (b) estimated reserves for crude oil, natural gas and NGLs, (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, 2024, the Company has used a weighted average discount rate of 5.63% at year-end 2024 for the primary U.S. plans. This weighted average discount rate is 0.5% higher than prior year, which decreased the Company’s recorded liabilities for retirement plans compared to a year ago. The Company assumed a return on plan assets of 7.60% for the primary U.S. plan and 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 2025 are expected to be $5.3 million lower than in 2024 primarily due to the decrease in the benefit obligations at December 31, 2024 compared to the prior year, which decreases the interest cost recognized in net periodic benefit costs.

In 2024, the Company paid $35.5 million into various retirement plans and $13.0 million into postretirement plans. In 2025, the Company is expecting to fund payments of approximately $26.4 million into various retirement plans and $4.2 million for postretirement plans. The Company could be required to make additional and more significant funding payments to retirement plans in future years. Future required payments and the amount of liabilities recorded on the balance sheet associated with the plans could be unfavorably affected if the discount rate declines, the actual return on plan assets falls below the assumed return, or the health care cost trend rate increase is higher than expected.

Recent Accounting Pronouncements

See Note B in 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 2024 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**	2025	2026 - 2027	2028 - 2029	After 2029
Debt, excluding interest	**$ 1,284.8**	$ —	$ 78.9	$ 266.2	$ 939.7
Operating and finance leases	**1,009.6**	291.7	192.5	118.0	407.4
Capital expenditures, drilling rigs and other [1]	**1,294.4**	469.8	339.2	160.2	325.2
Other long-term liabilities, including debt interest [2]	**2,618.0**	197.2	262.0	194.9	1,963.9
Total	**$ 6,206.8**	$ 958.7	$ 872.6	$ 739.3	$ 3,636.2

[1] Capital expenditures, drilling rigs and other includes $25.3 million, $13.7 million, $7.3 million and $1.1 million, in 2025 for approved capital projects in non-operated interests in the Gulf of America, U.S. Onshore, Canada Offshore and Other Offshore, respectively. Capital expenditures, drilling rigs and other includes $4.7 million in 2026 for approved capital projects in non-operated interests in the Gulf of America.

Also includes $73.1 million (2025), $138.4 million (2026 - 2027), $114.0 million (2028 - 2029) and $256.5 million (After 2029) for pipeline transportation commitments in Canada.

Also includes $3.6 million (2025), $7.1 million (2026 - 2027), $7.1 million (2028 - 2029) and $17.2 million (After 2029) for long-term take or pay commitments relating to natural gas processing in Canada.

Also includes approximately $7.2 million (2025), $25.5 million (2026 - 2027), $25.3 million (2028 - 2029) and $120.0 million (After 2029) for Other Offshore for the purpose of supporting future development activities in Vietnam.

[2] Other long-term liabilities, including debt interest, includes future cash outflows for ARO liabilities.

The Company has entered into agreements to lease production facilities for various producing oil fields as well as other arrangements that require 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 $189.7 million as of December 31, 2024.

Material off-balance sheet arrangements – Certain U.S. transportation contracts require minimum monthly payments through 2045, while Canada Onshore transportation and 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

The oil and natural gas industry is impacted by global commodity pricing. As a result, the prices for the Company's primary products are often volatile and are affected by the levels of supply and demand for energy. As discussed in the "Results of Operations" section on revenues, on page 37, lower average crude oil price during 2024 directly impacted the Company's product sales revenue.

As of close on February 25, 2025, forward price curves for existing forward contracts for the remainder of 2025 and 2026 are shown in the table below:

	2025	2026
WTI ($/BBL)	67.60	64.93
NYMEX ($/MMBTU)	4.44	4.21
AECO (US$ Equivalent/MCF)	1.49	2.21

In 2024, liquids from continuing operations represented approximately 56% of total hydrocarbons produced on a barrels of oil equivalent basis. In 2025, the Company's ratio of hydrocarbon production represented by liquids is expected to be 57%. If the prices for crude oil and natural gas are lower in 2025 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.

The Company currently expects average daily production in 2025 to be between 181,100 and 189,100 BOEPD (including a noncontrolling interest of 6,600 BOEPD). If significant price declines occur, the Company will review the option of production curtailments to avoid incurring losses on certain produced barrels.

Similar to the overall inflation and higher interest rates in the wider economy, the oil and natural gas industry and the Company are observing higher costs for goods and services used in E&P operations. Murphy continues to manage input costs through its dedicated procurement department focused on managing supply chain and other costs to deliver cash flow from operations.

We cannot predict what impact economic factors (including, but not limited to, inflation, global conflicts and possible economic recession) 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 2025 is expected to be between $1,135 million and $1,285 million, excluding 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 2025 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 plans to utilize surplus cash (not planned to be used by operations, investing activities, dividends or payment to noncontrolling interests), in accordance with the Company's capital allocation framework designed to allow for additional shareholder returns and debt reduction. Details of the framework can be found in the "Capital Allocation Framework" section of the Company's Form 8-K filed on August 4, 2022 and Form 8-K filed on August 8, 2024. The Board has authorized a share repurchase program whereby the Company can repurchase up to $1,100 million of the Company's common stock. As of December 31, 2024, the Company had $650.1 million of its common stock remaining available to repurchase under the program.

Subsequent to year end, as of February 25, 2025, the Company repurchased 3.4 million shares of its common stock in open-market transactions for $95.1 million, excluding taxes and fees. As of this date, the Company had $555.0 million of its common stock remaining available to repurchase under the program.

In addition, subsequent to the balance sheet date, on January 30, 2025, the Board of Directors declared a quarterly cash dividend on the Common Stock of Murphy Oil Corporation of $0.325 per share, or $1.30 per share on an annualized basis. The dividend is payable on March 3, 2025, to stockholders of record as of February 18, 2025.

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 RCF (see Note F).

As of February 25, 2025, the Company has entered into 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
Canada	Natural Gas	Fixed price forward sales	40	C$2.75	1/1/2025	12/31/2025
Canada	Natural Gas	Fixed price forward sales	50	C$3.03	1/1/2026	12/31/2026

Area	Commodity	Type	Volumes (MMCF/d)	Price/MCF	Remaining Period Start Date	Remaining Period End Date
United States	Natural Gas	Fixed price derivative swap	40	US$3.58	2/1/2025	6/30/2025
United States	Natural Gas	Fixed price derivative swap	60	US$3.65	7/1/2025	9/30/2025
United States	Natural Gas	Fixed price derivative swap	60	US$3.74	10/1/2025	12/31/2025

Forward-Looking Statements

This Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. 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, results and plans, are subject to inherent risks, uncertainties and assumptions (many of which are beyond our control) and are not guarantees of performance. In particular, statements, express or implied, concerning the Company’s future operating results or activities and returns or the Company's ability and decisions to replace or increase reserves, increase production, generate returns and rates of return, replace or increase drilling locations, reduce or otherwise control operating costs and expenditures, generate cash flows, pay down or refinance indebtedness, achieve, reach or otherwise meet initiatives, plans, goals, ambitions or targets with respect to emissions, safety matters or other ESG (environmental/social/governance) matters, make capital expenditures or pay and/or increase dividends or make share repurchases and other capital allocation decisions are forward-looking statements. Factors that could cause one or more of these future events, results or plans not to occur as implied by any forward-looking statement, which consequently could cause actual results or activities to differ materially from the expectations expressed or implied by such forward-looking statements, include, but are not limited to: macro conditions in the oil and natural gas industry, including supply/demand levels, actions taken by major oil exporters and the resulting impacts on commodity prices; geopolitical concerns; 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, banking system or economies in general, including inflation and trade policies. 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 13 of this Annual Report on Form 10-K. Investors and others should note that we may announce material information using SEC filings, press releases, public conference calls, webcasts and the investors page of our website. We may use these channels to distribute material information about the Company; therefore, we encourage investors, the media, business partners and others interested in the Company to review the information we post on our website. The information on our website is not part of, and is not incorporated into, this report. Murphy Oil Corporation 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 prices of crude oil, natural gas and petroleum products, foreign currency exchange rates and interest rates. As described in Note K, Murphy periodically makes use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions.

Commodity Price Risk

There were commodity transactions in place as of December 31, 2024, covering certain future U.S. natural gas sales volumes in 2025. A 10% increase in the respective benchmark price of these commodities would have increased the net payable associated with these derivative contracts by approximately $2.5 million, while a 10% decrease would have decreased the recorded payable by a similar amount, resulting in a receivable.

Foreign Exchange Risk

There were no derivative foreign exchange contracts in place as of December 31, 2024.

Interest Rate Risk

At December 31, 2024, long-term debt was $1,274.5 million. The fixed-rate notes have a weighted average coupon of 6.1%. The Company's RCF provides for variable interest rate borrowings; however, we did not have any borrowings outstanding as of December 31, 2024 and, therefore, no related exposure to interest rate risk.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages 66 through 123 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 the Company to ensure that material information relating to the Company and its consolidated subsidiaries is made known to the officers who certify the Company's financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation, with the participation of the Company's management, as of December 31, 2024, 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, 2024. 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, 2024 and their report is included on page 65 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 2024 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. OTHER INFORMATION

During the three months ended December 31, 2024, no director or officer of the Company adopted or terminated a “Rule 10b5-1 trading arrangement” or “non-Rule 10b5-1 trading arrangement,” as each term is defined in Item 408(a) of Regulation S-K.

Item 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

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 14, 2025 under the captions "Election of Directors" and "The Board and Committees."

Murphy Oil has adopted a Code of Ethical Conduct for Executive Management, which can be found under the Corporate Governance tab at ir.murphyoilcorp.com. Stockholders may also obtain, free of charge, a copy of the Code of Ethical Conduct for Executive Management by writing to the Corporate Secretary at 9805 Katy Fwy, Suite G-200, Houston, TX 77024. Any future amendments to or waivers of the Code of Ethical Conduct for Executive Management will be posted on the Company's Website.

Murphy Oil has also adopted an insider trading policy governing the purchase, sale, and/or other dispositions of our securities by our directors, officers, employees and contractors and consultants who have access to material nonpublic information, as well as the Company itself, that we believe is reasonably designed to promote compliance with insider trading laws, rules and regulations, and the exchange listing standards applicable to us. A copy of our insider trading policy, including any amendments thereto, is filed as Exhibit 19.1 to this Form 10-K.

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 14, 2025 under the captions "Compensation Discussion and Analysis" and "How We Are Compensated" and in various compensation schedules.

As required by U.S. federal securities laws, the Company implemented its incentive-based compensation recoupment (clawback) policy providing for the recovery of erroneously awarded incentive-based compensation received by current or former executive officers. We have filed our written recoupment policy as Exhibit 97.1 to this Form 10-K report and as of December 31, 2024, there have been no accounting restatements requiring compensation recoupment.

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 14, 2025 under the caption "Our Stockholders" and in the "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 14, 2025 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 14, 2025 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.

PART IV

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 filed February 27, 2019
3.1	Certificate of Incorporation of Murphy Oil Corporation, as amended effective May 11, 2005	Exhibit 3.1 to Form 10-K filed February 28, 2011
3.2	By-Laws of Murphy Oil Corporation, as amended effective August 5, 2020	Exhibit 3.2 to Form 10-Q filed August 6, 2020
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 filed March 16, 2005
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 filed March 16, 2005
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	Second Supplemental Indenture dated as of November 30, 2012, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 5.125% Notes due 2042	Exhibit 4.1 to Form 8-K filed November 30, 2012
4.5	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
4.6	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934	Exhibit 4.9 to Form 10-K filed February 27, 2020
4.7	Sixth Supplemental Indenture dated as of March 5, 2021, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, and Wells Fargo Bank, National Association as series trustee, relating to 6.375% Notes due 2028	Exhibit 4.2 to Form 8-K filed March 5, 2021
4.8	Seventh Supplemental Indenture dated as of October 3, 2024,between Murphy Oil Corporation and Regions Bank, as trustee, relating to 6.000% Notes due 2032	Exhibit 4.2 to Form 8-K filed October 3, 2024
10.1	Murphy Oil Corporation Annual Incentive Plan	Exhibit 10.3 to Form 10-K filed February 25, 2022
10.2	Murphy Oil Corporation 2018 Long-Term Incentive Plan	Exhibit B to definitive proxy statement filed March 23, 2018
10.3	Amendment to the Murphy Oil Corporation 2018 Long-Term Incentive Plan	Exhibit 10.15 to Form 10-K filed February 27, 2020

10.4	Form of employee performance-based restricted stock unit – stock settled grant agreement (2018 Long-Term Incentive Plan)	Exhibit 10.14 to Form 10-K filed February 27, 2019
10.5	Form of employee performance-based restricted stock unit – stock settled grant agreement (2018 Long-Term Incentive Plan)	Exhibit 10.17 to Form 10-K filed February 27, 2020
10.6	Form of employee time-based restricted stock unit – stock settled 3-year grant agreement (2018 Long-Term Incentive Plan)	Exhibit 10.15 to Form 10-K filed February 27, 2019
10.7	Form of employee time-based restricted stock unit – stock settled 5-year grant agreement (2018 Long-Term Incentive Plan)	Exhibit 10.16 to Form 10-K filed February 27, 2019
10.8	Murphy Oil Corporation 2020 Long-Term Incentive Plan	Exhibit A to definitive proxy statement filed March 30, 2020
10.9	Form of employee performance-based restricted stock unit – stock settled grant agreement (2020 LTI Plan)	Exhibit 10.21 to Form 10-K filed February 26, 2021
10.10	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 February 26, 2021
10.11	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 February 26, 2021
10.12	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 February 26, 2021
10.13	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 February 26, 2021
10.14	Murphy Oil Corporation 2018 Stock Plan for Non-Employee Directors	Exhibit A to definitive proxy statement filed March 23, 2018
10.15	First Amendment to the 2018 Stock Plan for Non-Employee Directors	Exhibit 10.1 to Form 8-K filed April 25, 2018
10.16	Second Amendment to the 2018 Stock Plan for Non-Employee Directors	Exhibit 10.24 to Form 10-K filed February 27, 2020
10.17	Form of non-employee director restricted stock unit award – stock settled grant agreement (2018 NED Plan)	Exhibit 10.20 to Form 10-K filed February 27, 2019
10.18	Form of non-employee director restricted stock unit award – stock settled grant agreement (2018 NED Plan)	Exhibit 10.26 to Form 10-K filed February 27, 2020
10.19	Murphy Oil Corporation 2021 Stock Plan for Non-Employee Directors	Exhibit A to definitive proxy statement filed March 26, 2021
10.20	Form of non-employee director restricted stock unit award – stock settled grant agreement (2021 NED Plan)	Exhibit 10.27 to Form 10-Q filed August 5, 2021
10.21	Murphy Oil Corporation Non-Qualified Deferred Compensation Plan for Non-Employee Directors	Exhibit 10.6 to Form 10-K filed February 26, 2016
10.22	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
10.23	Form of employee performance-based restricted stock unit (2020 LTI Plan)	Exhibit 10.30 to Form 10-K filed February 23, 2024
10.24	Form of employee time-based restricted stock unit – A (2020 LTI Plan)	Exhibit 10.31 to Form 10-K filed February 23, 2024
10.25	Form of employee time-based restricted stock unit – B (2020 LTI Plan)	Exhibit 10.32 to Form 10-K filed February 23, 2024
10.26	Form of employee time-based restricted stock unit – C (2020 LTI Plan)	Exhibit 10.33 to Form 10-K filed February 23, 2024
10.27	Form of employee time-based restricted stock unit – D (2020 LTI Plan)	Exhibit 10.34 to Form 10-K filed February 23, 2024
10.28	Form of non-employee director elective restricted stock unit (2021 NED Plan)	Exhibit 10.35 to Form 10-Q filed May 2, 2024
10.29	Severance Protection Agreement dated as of August 7, 2013 between Murphy Oil Corporation and Roger W. Jenkins	Exhibit 10.1 to Form 8-K filed August 9, 2013

PART IV

10.30	Amendment to Severance Protection Agreement dated as of August 7, 2013, between Murphy Oil Corporation and Roger W. Jenkins	Exhibit 10.1 to Form 10-Q filed May 2, 2019
10.31	Credit Agreement, dated as of October 7, 2024, among Murphy Oil Corporation, Murphy Exploration & Production Company – International and Murphy Oil Company Ltd., as borrowers, JPMorgan Chase Bank N.A., as administrative agent, and the lenders party thereto	Exhibit 10.1 to Form 8-K filed October 7, 2024
*10.32	Form of Severance Protection Agreement	
*10.33	First Amendment to the New Credit Agreement dated as of February 6, 2025 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 hereto	
*19.1	Murphy Oil Corporation Insider Trading Policy	
*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.	
*23.4	Consent of Netherland, Sewell & Associates, Inc.	
*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	
97.1	Murphy Oil Corporation Compensation Recoupment Policy	Exhibit 10.29 to Form 10-K filed February 23, 2024
*99.1	Ryder Scott independent reserves audit report for MP GOM JV	
*99.2	McDaniel independent reserves audit report for Canada Onshore proved crude oil and natural gas reserves	
*99.3	Netherland, Sewell & Associates, Inc. independent reserves audit report U.S. Gulf of Mexico	
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document	
101.SCH	Inline XBRL Taxonomy Extension Schema Document	
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document	
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document	
101.LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document	
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase	
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)	

Item 16. FORM 10-K SUMMARY

None.

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/ ERIC M. HAMBLY	Date:	February 27, 2025
	Eric M. Hambly, President and Chief Executive Officer		

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 27, 2025 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ CLAIBORNE P. DEMING	/s/ JAMES V. KELLEY
Claiborne P. Deming, Chairman and Director	James V. Kelley, Director
/s/ ERIC M. HAMBLY	/s/ R. MADISON MURPHY
Eric M. Hambly, President and Chief Executive Officer and Director (Principal Executive Officer)	R. Madison Murphy, Director
/s/ LAWRENCE R. DICKERSON	/s/ JEFFREY W. NOLAN
Lawrence R. Dickerson, Director	Jeffrey W. Nolan, Director
/s/ MICHELLE A. EARLEY	/s/ ROBERT N. RYAN, JR.
Michelle A. Earley, Director	Robert N. Ryan, Jr., Director
/s/ ELISABETH W. KELLER	/s/ LAURA A. SUGG
Elisabeth W. Keller, Director	Laura A. Sugg, Director
/s/ ROBERT B. TUDOR, III	/s/ THOMAS J. MIRELES
Robert B. Tudor, III, Director	Thomas J. Mireles, Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ PAUL D. VAUGHAN	
Paul D. Vaughan 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 63.

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, 2024.

KPMG LLP has performed an audit of the Company's internal control over financial reporting, and their opinion thereon can be found on page 65.

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, 2024 and 2023, 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, 2024, 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, 2024 and 2023, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2024, 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, 2024, 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 27, 2025 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 Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates 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 a critical audit matter 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

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, 2024, the Company recorded depreciation, depletion, and amortization expense of $865.8 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.

/s/ KPMG LLP

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

Houston, Texas

February 27, 2025

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the 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, 2024, 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, 2024, 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, 2024 and 2023, 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, 2024, and the related notes and financial statement schedule II (collectively, the consolidated financial statements), and our report dated February 27, 2025 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 27, 2025

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31 (Thousands of dollars except share amounts)		2024	2023
ASSETS			
Current assets			
Cash and cash equivalents		**$ 423,569**	$ 317,074
Accounts receivable, net		**272,530**	343,992
Inventories	Note E	**54,858**	54,454
Prepaid expenses		**34,322**	36,674
Total current assets		**785,279**	752,194
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $13,811,539 in 2024 and $13,135,385 in 2023	Note D	**8,054,653**	8,225,197
Operating lease assets	Note T	**777,536**	745,185
Deferred income taxes	Note H	**—**	435
Deferred charges and other assets		**50,011**	43,686
Total assets		**$ 9,667,479**	$ 9,766,697
LIABILITIES AND EQUITY			
Current liabilities			
Current maturities of long-term debt, finance lease	Note F	**$ 871**	$ 723
Accounts payable		**472,165**	446,891
Income taxes payable		**19,003**	21,007
Other taxes payable		**31,685**	29,339
Operating lease liabilities	Note T	**253,208**	207,840
Other accrued liabilities		**117,802**	130,033
Current asset retirement obligations [1]	Note G	**48,080**	10,712
Total current liabilities		**942,814**	846,545
Long-term debt, including finance lease obligation	Note F	**1,274,502**	1,328,352
Asset retirement obligations	Note G	**960,804**	904,051
Deferred credits and other liabilities		**274,345**	309,605
Non-current operating lease liabilities	Note T	**537,381**	551,845
Deferred income taxes	Note H	**335,790**	276,646
Total liabilities		**$ 4,325,636**	$ 4,217,044
Equity			
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued		**$ —**	$ —
Common Stock, par $1.00, authorized 450,000,000 shares, issued 195,100,628 shares in 2024 and 195,100,628 shares in 2023		**195,101**	195,101
Capital in excess of par value		**848,950**	880,297
Retained earnings		**6,773,289**	6,546,079
Accumulated other comprehensive loss	Note N	**(628,072)**	(521,117)
Treasury stock		**(1,995,018)**	(1,737,566)
Murphy Shareholders' Equity		**5,194,250**	5,362,794
Noncontrolling interest		**147,593**	186,859
Total equity		**5,341,843**	5,549,653
Total liabilities and equity		**$ 9,667,479**	$ 9,766,697

[1] The prior-period amount has been reclassified to conform to the current period presentation.

The accompanying notes are an integral part of these consolidated financial statements.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

Years Ended December 31 (Thousands of dollars except per share amounts)	2024	2023	2022
Revenues and other income			
Revenue from production	**$ 3,014,856**	$ 3,376,639	$ 4,038,451
Sales of purchased natural gas	**3,742**	72,215	181,689
Total revenue from sales to customers	**3,018,598**	3,448,854	4,220,140
(Loss) on derivative instruments	**(1,707)**	—	(320,410)
Gain on sale of assets and other operating income	**11,583**	11,293	32,932
Total revenues and other income	**3,028,474**	3,460,147	3,932,662
Costs and expenses			
Lease operating expenses	**936,960**	784,391	679,342
Severance and ad valorem taxes	**39,162**	42,787	57,012
Transportation, gathering and processing	**210,827**	232,985	212,711
Costs of purchased natural gas	**3,147**	51,682	171,991
Exploration expenses, including undeveloped lease amortization	**133,538**	234,776	133,197
Selling and general expenses	**110,085**	117,306	131,121
Depreciation, depletion and amortization	**865,753**	861,602	776,817
Accretion of asset retirement obligations	**52,511**	46,059	46,243
Impairment of assets	**62,909**	—	—
Other operating expense	**10,989**	46,530	137,518
Total costs and expenses	**2,425,881**	2,418,118	2,345,952
Operating income from continuing operations	**602,593**	1,042,029	1,586,710
Other income (loss)			
Other income (loss)	**70,902**	(8,587)	14,310
Interest expense, net	**(105,926)**	(112,373)	(150,759)
Total other loss	**(35,024)**	(120,960)	(136,449)
Income from continuing operations before income taxes	**567,569**	921,069	1,450,261
Income tax expense	**78,272**	195,921	309,464
Income from continuing operations	**489,297**	725,148	1,140,797
Loss from discontinued operations, net of income taxes	**(2,812)**	(1,467)	(2,078)
Net income including noncontrolling interest	**486,485**	723,681	1,138,719
Less: Net income attributable to noncontrolling interest	**79,314**	62,122	173,672
NET INCOME ATTRIBUTABLE TO MURPHY	**$ 407,171**	$ 661,559	$ 965,047
NET INCOME (LOSS) PER COMMON SHARE – BASIC			
Continuing operations	**$ 2.73**	$ 4.27	$ 6.23
Discontinued operations	**(0.02)**	(0.01)	(0.01)
Net income	**$ 2.71**	$ 4.26	$ 6.22
NET INCOME (LOSS) PER COMMON SHARE – DILUTED			
Continuing operations	**$ 2.72**	$ 4.23	$ 6.14
Discontinued operations	**(0.02)**	(0.01)	(0.01)
Net income	**$ 2.70**	$ 4.22	$ 6.13
Cash dividends per common share	**$ 1.200**	$ 1.100	$ 0.825
Average common shares outstanding (thousands)			
Basic	**150,011**	155,234	155,277
Diluted	**151,027**	156,646	157,475

The accompanying notes are an integral part of these consolidated financial statements.

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

Years Ended December 31 (Thousands of dollars)	2024	2023	2022
Net income including noncontrolling interest	**$ 486,485**	$ 723,681	$ 1,138,719
Other comprehensive income (loss), net of tax			
Net (loss) gain from foreign currency translation	**(134,692)**	36,598	(106,335)
Retirement and postretirement benefit plans	**27,737**	(23,029)	99,360
Other comprehensive income (loss)	**(106,955)**	13,569	(6,975)
Comprehensive income including noncontrolling interest	**379,530**	737,250	1,131,744
Less: Comprehensive income attributable to noncontrolling interest	**79,314**	62,122	173,672
COMPREHENSIVE INCOME ATTRIBUTABLE TO MURPHY	**$ 300,216**	$ 675,128	$ 958,072

The accompanying notes are an integral part of these consolidated financial statements.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 (Thousands of dollars)	2024	2023	2022
Operating Activities			
Net income including noncontrolling interest	$ 486,485	$ 723,681	$ 1,138,719
Adjustments to reconcile net income to net cash provided by continuing operations activities			
Depreciation, depletion and amortization	865,753	861,602	776,817
Unsuccessful exploration well costs and previously suspended exploration costs	73,201	169,795	82,085
Deferred income tax expense	72,434	179,823	286,079
Impairment of assets	62,909	—	—
Accretion of asset retirement obligations	52,511	46,059	46,243
Long-term non-cash compensation	45,057	61,953	89,246
Amortization of undeveloped leases	9,587	10,925	13,300
Loss from discontinued operations	2,812	1,467	2,078
Mark-to-market loss (gain) on derivative instruments	1,707	—	(214,788)
Contingent consideration payment	—	(139,574)	—
Mark-to-market loss on contingent consideration	—	7,113	78,285
Gain from sale of assets	—	—	(17,899)
Other operating activities, net	(18,349)	(74,728)	(34,193)
Net decrease (increase) in non-cash working capital	74,883	(99,361)	(65,728)
Net cash provided by continuing operations activities	1,728,990	1,748,755	2,180,244
Investing Activities			
Property additions and dry hole costs	(908,164)	(1,066,015)	(985,461)
Acquisition of oil and natural gas properties	—	(35,578)	(128,538)
Proceeds from sales of property, plant and equipment	—	102,913	4,528
Net cash required by investing activities	(908,164)	(998,680)	(1,109,471)
Financing Activities			
Retirement of debt	(650,112)	(498,175)	(647,707)
Early redemption of debt cost	(15,700)	—	(8,295)
Debt issuance	600,000	—	—
Debt issuance cost	(10,145)	—	—
Borrowings on revolving credit facility	350,000	600,000	400,000
Repayment of revolving credit facility	(350,000)	(600,000)	(400,000)
Issue costs of revolving credit facility	(14,718)	(20)	(14,353)
Repurchase of common stock	(301,350)	(150,022)	—
Cash dividends paid	(179,961)	(170,978)	(128,219)
Distributions to noncontrolling interest	(118,580)	(29,382)	(183,038)
Withholding tax on stock-based incentive awards	(25,310)	(14,276)	(17,631)
Finance lease obligation payments	(665)	(622)	(636)
Contingent consideration payment	—	(60,243)	(81,742)
Net cash required by financing activities	(716,541)	(923,718)	(1,081,621)
Net cash required by discontinued operations	—	—	(14,500)
Effect of exchange rate changes on cash and cash equivalents	2,210	(1,246)	(3,873)
Net increase (decrease) in cash and cash equivalents	106,495	(174,889)	(29,221)
Cash and cash equivalents at beginning of period	317,074	491,963	521,184
Cash and cash equivalents at end of period	$ 423,569	$ 317,074	$ 491,963

The accompanying notes are an integral part of these consolidated financial statements.

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

Years Ended December 31 (Thousands of dollars except number of shares)	2024	2023	2022
Common Stock			
Balance at beginning and end of year - par $1.00, authorized 450,000,000 shares at December 31, 2024, 2023 and 2022, issued 195,100,628 shares at December 31, 2024, 2023 and 2022	**195,101**	195,101	195,101
Capital in Excess of Par Value			
Balance at beginning of year	**880,297**	893,578	926,698
Restricted stock transactions and other [1]	**(70,539)**	(42,667)	(58,362)
Share-based compensation	**39,192**	29,386	25,242
Balance at end of year	**848,950**	880,297	893,578
Retained Earnings			
Balance at beginning of year	**6,546,079**	6,055,498	5,218,670
Net income attributable to Murphy	**407,171**	661,559	965,047
Cash dividends paid	**(179,961)**	(170,978)	(128,219)
Balance at end of year	**6,773,289**	6,546,079	6,055,498
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(521,117)**	(534,686)	(527,711)
Foreign currency translation (loss) gain, net of income taxes	**(134,692)**	36,598	(106,335)
Retirement and postretirement benefit plans, net of income taxes	**27,737**	(23,029)	99,360
Balance at end of year	**(628,072)**	(521,117)	(534,686)
Treasury Stock			
Balance at beginning of year	**(1,737,566)**	(1,614,717)	(1,655,447)
Repurchase of common stock	**(302,681)**	(151,241)	—
Awarded restricted stock, net of forfeitures	**45,229**	28,392	40,730
Balance at end of year – 49,255,504 shares of common stock in 2024, 42,351,986 shares of common stock in 2023 and 39,633,309 shares of common stock in 2022	**(1,995,018)**	(1,737,566)	(1,614,717)
Murphy Shareholders' Equity	**5,194,250**	5,362,794	4,994,774
Noncontrolling Interest			
Balance at beginning of year	**186,859**	154,119	163,485
Net income attributable to noncontrolling interest	**79,314**	62,122	173,672
Distributions to noncontrolling interest owners	**(118,580)**	(29,382)	(183,038)
Balance at end of year	**147,593**	186,859	154,119
Total Equity	**$ 5,341,843**	$ 5,549,653	$ 5,148,893

[1] Prior-period amounts have been aggregated to conform to the current period presentation.

The accompanying notes are an integral part of these consolidated financial statements.

These notes are an integral part of the consolidated financial statements of Murphy Oil Corporation and Consolidated Subsidiaries (Murphy/the Company) on pages 71-105 of the Form 10-K report.

Note A – Significant Accounting Policies

NATURE OF BUSINESS – Murphy Oil Corporation is an international oil and natural gas company that conducts its business through various operating subsidiaries. The Company primarily produces oil and natural gas in the U.S. and Canada and conducts oil and natural gas exploration activities worldwide.

BASIS OF PRESENTATION AND PRINCIPLES OF CONSOLIDATION – The consolidated financial statements include the accounts of Murphy Oil Corporation and all majority-owned subsidiaries and are presented in conformity with GAAP. 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. Murphy reports 100% of the sales volume, revenues, costs, assets and liabilities including the 20% noncontrolling interest in MP GOM in accordance with accounting for noncontrolling interest as prescribed by Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 810-10-45, “Consolidations”. Other investments are generally carried at cost. Intercompany accounts and transactions are eliminated.

USE OF ESTIMATES – Preparing the financial statements of the Company in accordance with GAAP requires management to make a number of estimates and assumptions that affect the reporting of amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results may differ from the estimates.

REVENUE RECOGNITION – Revenues from sales of crude oil, natural gas and NGLs 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, 2024 and 2023, 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, 2024 and 2023, 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. Trade accounts receivable are recorded at the invoiced amount and do not bear interest. 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.

Note A – Significant Accounting Policies (Continued)

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 including 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 E.

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 a major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such a 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 assessed when there is an indication 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 its fair value. See Note D for further discussion of impairment charges.

The Company records a liability for 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, plugging and abandoning wells and restoring sites are charged against the related liability. Any difference between costs incurred upon settlement of an ARO and the recorded liability is recognized as a gain or loss in the Company’s earnings. See Note G for further discussion.

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, “Leases”. 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 Sheets as “Operating lease assets” with the corresponding lease liabilities presented in “Operating lease liabilities” and “Non-current operating lease liabilities”. Finance lease assets are presented on the Consolidated Balance Sheets within

"Property, plant and equipment", with the corresponding liabilities presented in "Current maturities of long-term debt, finance lease" and "Long-term debt, including finance lease obligation".

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. 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 arising from 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 it may decide that the contract is not a hedge for accounting purposes, and thenceforth, recognize changes in the fair value of the contract in earnings. Sale and purchase contracts in the normal course of business are not designated as hedges for accounting purposes.

The Company documents the relationship between the derivative instrument designated as a hedge and the hedged items as well as its risk management objectives and strategy. 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

Note A – Significant Accounting Policies (Continued)

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 O.

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 (PSUs) with market based conditions, and expense is recognized over the three-year vesting period. The fair value of PSUs with performance-based conditions and time-based restricted stock units (RSUs) 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 PSUs 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 (SARs) and cash-settled restricted time-based stock units (CRSUs) as liability awards. Expense associated with these awards is 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 SARs and the period-end price of the Company's common stock for time-based CRSUs. When SARs are exercised and when CRSUs settle, the Company adjusts previously recorded expense to the final amounts paid out in cash for these awards. See Note I.

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 J.

NET INCOME (LOSS) PER COMMON SHARE – Basic net 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. See Note L.

Note B – New Accounting Principles and Recent Accounting Pronouncements

Accounting Principles Adopted

Reportable Segment Disclosures. In November 2023, the FASB issued Accounting Standards Update (ASU) *2023-07 Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures*. The standard requires additional disclosures about operating segments, including segment expense information provided to the chief operating decision maker, and extends certain disclosure requirements to interim periods. The Company adopted this standard in the fourth quarter of 2024. The adoption did not impact the determination of significant segments and had no material impact on the Company's consolidated financial statements. These new disclosure requirements are applied retrospectively to all prior periods included in the financial statements. Refer to Note S.

Note B - New Accounting Principles and Recent Accounting Pronouncements (Continued)

Recent Accounting Pronouncements

Expense Disaggregation Disclosures. In November 2024, the FASB issued *ASU 2024-03 Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses.* The standard becomes effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. The standard requires specified information about certain costs and expenses presented on the face of the income statement to be further disaggregated in the notes to the financial statements. In addition, the standard requires certain expense and cost information that is not separately disaggregated to be qualitatively described. We expect this ASU to only impact our disclosures with no impacts to our results of operations, cash flows and financial condition.

Income Tax Disclosures. In December 2023, the FASB issued *ASU 2023-09 Income Taxes (Topic 740): Improvements to Income Tax Disclosures.* The standard becomes effective for annual periods beginning after December 15, 2024. The update requires financial statements to include consistent categories and greater disaggregation of information in the rate reconciliation, as well as income taxes paid disaggregated by jurisdiction. We expect this ASU to only impact our disclosures with no impacts to our results of operations, cash flows and financial condition.

Note C – Revenue from Contracts with Customers

Nature of Goods and Services

The Company explores for and produces crude oil, natural gas and NGLs (collectively referred to as oil and natural gas) in select basins around the world. The Company's revenue from sales of oil and natural gas production activities is 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, natural gas and NGLs.

For operated oil and natural gas production where a 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 GAAP.

U.S. - In the U.S., the Company primarily produces oil and natural gas from fields in the Eagle Ford Shale area of South Texas and in the Gulf of America. Revenue is generally recognized when oil and natural gas is 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. The Company also purchases natural gas in Canada to meet certain sales commitments.

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 (Continued)

The Company's revenues and other income for each of the three years presented were as follows.

	Years Ended December 31,		
(Thousands of dollars)	**2024**	2023	2022
Net crude oil and condensate revenue			
United States - Onshore	**$ 586,584**	$ 676,139	$ 856,219
United States - Offshore [1]	**1,777,723**	2,072,353	2,229,658
Canada - Onshore	**70,855**	78,088	131,400
Canada - Offshore	**193,961**	78,650	117,747
Other	**6,537**	11,022	22,824
Total crude oil and condensate revenue	**2,635,660**	2,916,252	3,357,848
Net natural gas liquids revenue			
United States - Onshore	**32,853**	33,178	64,015
United States - Offshore [1]	**38,858**	47,434	60,424
Canada - Onshore	**7,454**	8,914	18,338
Total natural gas liquids revenue	**79,165**	89,526	142,777
Net natural gas revenue			
United States - Onshore	**17,443**	21,346	64,037
United States - Offshore [1]	**50,329**	71,332	161,160
Canada - Onshore	**232,259**	278,183	312,629
Total natural gas revenue	**300,031**	370,861	537,826
Revenue from production	**3,014,856**	3,376,639	4,038,451
Sales of purchased natural gas [2]			
United States - Offshore	**—**	—	204
Canada - Onshore	**3,742**	72,215	181,485
Total sales of purchased natural gas	**3,742**	72,215	181,689
Total revenue from sales to customers	**3,018,598**	3,448,854	4,220,140
(Loss) on derivative instruments	**(1,707)**	—	(320,410)
Gain on sale of assets and other operating income	**11,583**	11,293	32,932
Total revenues and other income	**$ 3,028,474**	$ 3,460,147	$ 3,932,662

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

[2] Purchases of natural gas are reported on a gross basis when Murphy takes control of the product and has risks and rewards of ownership. Sales of natural gas are reported when the contractual performance obligations are satisfied. This occurs at the time the product is delivered to a third party purchaser at the contractually determinable price.

Contract Balances and Asset Recognition

As of December 31, 2024 and 2023, receivables from contracts with customers, net of royalties and associated payables, on the balance sheet from continuing operations, were $178.3 million and $193.7 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, 2024, 2023 or 2022.

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.

Note C - Revenue from Contracts with Customers (Continued)

Performance Obligations

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

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

The Company has entered into several long-term, fixed-price contracts in Canada. The underlying reason for entering a fixed price contract is generally unrelated to anticipated future prices or other observable data and serves a particular purpose in the Company's long-term strategy.

As of December 31, 2024, the Company had the following sales contracts in place which are expected to generate revenue from sales to customers for a period over 12 months starting at the inception of the contract:

Long-Term Contracts Outstanding at December 31, 2024

Location	Commodity	End Date	Description	Approximate Volumes
U.S.	Natural Gas and NGLs	Q2 2030	Deliveries from dedicated acreage in Eagle Ford	As produced
Canada	Natural Gas	Q4 2025	Contracts to sell natural gas at USD index pricing	25 MMCFD
Canada	Natural Gas	Q4 2026	Contracts to sell natural gas at USD index pricing	49 MMCFD
Canada	Natural Gas	Q4 2027	Contracts to sell natural gas at USD index pricing	30 MMCFD
Canada	Natural Gas	Q4 2028	Contracts to sell natural gas at USD index pricing	10 MMCFD
Canada	Natural Gas	Q4 2025	Contracts to sell natural gas at CAD fixed pricing	40 MMCFD
Canada	Natural Gas	Q4 2026	Contracts to sell natural gas at CAD fixed pricing	50 MMCFD
Canada	NGLs	Q2 2025	Contracts to sell NGLs at CAD index pricing	As produced

The fixed price contracts above are accounted for as normal sales and purchases for accounting purposes.

Note D – Property, Plant and Equipment

The Company's property, plant and equipment assets for the respective periods are presented as follows:

	December 31, 2024		December 31, 2023	
(Thousands of dollars)	**Cost**	**Net**	Cost	Net
Exploration and production [1]	**$ 21,716,358**	**$ 8,021,620** [2]	$ 21,228,490	$ 8,201,475 [2]
Corporate and other	**149,834**	**33,033**	132,092	23,722
Property, plant and equipment	**$ 21,866,192**	**$ 8,054,653**	$ 21,360,582	$ 8,225,197
[1] Includes unproved mineral rights as follows:	**$ 283,015**	**$ 151,341**	$ 351,000	$ 228,329

[2] Includes $13,335 in 2024 and $15,356 in 2023 related to administrative assets and support equipment.

Divestments

On September 15, 2023, the Company completed the previously announced divestment of certain non-core operated Kaybob Duvernay assets and all of our non-operated Placid Montney assets, located in Alberta, Canada for net cash proceeds of C$139.0 million. No gain or loss was recorded related to this transaction, and the effective date of the transaction was March 1, 2023.

Note D – Property, Plant and Equipment (Continued)

During the third quarter of 2022, the Company completed the disposition of its 62.5% working interest of the Thunder Hawk field for a purchase price of $20.0 million less closing adjustments of $23.1 million, resulting in a total net payment to the buyer of $3.1 million. Additionally, the buyer assumed the ARO liabilities of approximately $47.9 million. A $17.9 million gain on sale was recorded in the period related to the sale. In September 2022, the Company completed the disposition of its working interests in Block CA-2 in Brunei for contingent consideration valued at approximately $8.7 million. No gain or loss was recorded related to this sale.

Acquisitions

In August 2022, the Company acquired an additional working interest of 3.37% in the non-operated Lucius field for a purchase price of $78.5 million, net of closing adjustments. In June 2022, the Company acquired an additional working interest of 11.0% in the non-operated Kodiak field for a purchase price of $50.0 million, net of closing adjustments.

Impairments

In 2024, the Company recorded a pretax impairment charge of $62.9 million. In the first quarter of 2024, the Company recorded an impairment charge of $34.5 million related to the Calliope field, and in the fourth quarter of 2024, the Company recorded an impairment charge of $28.4 million related to the Nearly Headless Nick field. Both of the impairments were the result of operational issues that led to reserve reductions. There were no impairments recognized in 2023 and 2022.

The following table reflects the recognized before tax impairments for each of the three years presented.

(Thousands of dollars)	**2024**	2023	2022
United States - Offshore	**$ 62,909**	$ —	$ —
	$ 62,909	$ —	$ —

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, 2024, 2023 and 2022, the Company had total capitalized drilling costs pending the determination of proved reserves of $72.1 million, $49.1 million and $171.9 million, respectively. The following table reflects the net changes in capitalized exploratory well costs for each of the three years presented.

(Thousands of dollars)	**2024**	2023	2022
Beginning balance at January 1	**$ 49,118**	$ 171,860	$ 179,481
Additions pending the determination of proved reserves	**49,408**	48	33,440
Reclassifications to proved properties based on the determination of proved reserves	**—**	(82,185)	—
Divestment	**—**	—	(7,915)
Capitalized exploration well costs charged to expense	**(26,471)**	(40,605)	(33,146)
Ending balance at December 31	**$ 72,055**	$ 49,118	$ 171,860

Capital additions of $49.4 million, for the year ended December 31, 2024, are mainly for the non-operated Ocotillo #1 (Mississippi Canyon 40) exploration well in the Gulf of America and the Hai Su Vang-1X (Golden Sea Lion), Block 15/2-17 exploration well in Vietnam. Capitalized well costs charged to dry hole expense of $26.5 million, for the year ended December 31, 2024, related to the Hoffe Park #1 (Mississippi Canyon 166) exploration well.

The preceding table excludes well costs of $46.7 million and $129.2 million incurred and expensed directly to dry hole during the year ended December 31, 2024 and 2023, respectively. In 2024, these costs primarily include $27.6 million for the non-operated Orange #1 (Mississippi Canyon 216) and $26.1 million for the Sebastian #1 (Mississippi Canyon 387) exploration wells in the Gulf of America. In 2023, the amount primarily includes $82.0 million for the Chinook #7 (Walker Ridge 425) and $47.2 million for the non-operated Oso #1 (Atwater Valley 138) exploration wells in the Gulf of America.

Note D – Property, Plant and Equipment (Continued)

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed for each individual well.

	2024		2023		2022	
(Thousands of dollars)	**Amount**	**No. of Wells**	Amount	No. of Wells	Amount	No. of Wells
Aging of capitalized well costs						
Zero to one year	**$ 49,790**	**5**	$ —	—	$ 15,527	2
One to two years	**—**	**—**	—	—	13,307	2
Two to three years	**—**	**—**	2,698	1	—	—
Three years or more	**22,265**	**3**	46,420	3	143,026	5
	$ 72,055	**8**	$ 49,118	4	$ 171,860	9

Of the $22.3 million of exploratory well costs capitalized more than one year at December 31, 2024, $15.1 million was in Vietnam, $4.4 million was in Canada and $2.7 million was in Brunei. 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 – Inventories

Inventories consisted of the following for the respective periods presented:

	December 31,	
(Thousands of dollars)	**2024**	2023
Unsold crude oil	**$ 18,745**	$ 10,304
Materials and supplies	**36,113**	44,150
Inventories	**$ 54,858**	$ 54,454

Note F – Financing Arrangements and Debt

Long-term debt for the respective periods presented consisted of the following:

	December 31,	
(Thousands of dollars)	**2024**	2023
Notes payable		
5.875% notes, due December 2027	**$ 78,899**	$ 443,249
6.375% notes, due July 2028	**148,590**	372,226
7.05% notes, due May 2029	**117,582**	179,708
6.00% notes, due October 2032	**600,000**	—
5.875% notes, due December 2042 [1]	**339,761**	339,761
Total notes payable	**1,284,832**	1,334,944
Unamortized debt issuance cost and discount on notes payable	**(14,336)**	(10,107)
Total notes payable, net of unamortized discount	**1,270,496**	1,324,837
Finance lease obligations, due through November 2034	**4,877**	4,238
Total debt including current maturities	**1,275,373**	1,329,075
Current maturities	**(871)**	(723)
Total long-term debt	**$ 1,274,502**	$ 1,328,352

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

The amounts of long-term principal repayable over each of the next five years and thereafter are as follows: nil in 2025, nil in 2026, $78.9 million in 2027, $148.6 million in 2028, $117.6 million in 2029 and $939.8 million thereafter.

The Company also has a shelf registration statement on file with the SEC that permits the offer and sale of debt and/or equity securities through October 15, 2027.

Revolving Credit Facility

During the fourth quarter of 2024, the Company entered into a credit agreement governing a $1.35 billion senior unsecured guaranteed RCF with a maturity date of October 7, 2029. The RCF extends the borrowing term and increases the borrowing capacity of the previous RCF. On the date the Company achieves certain credit ratings (Investment Grade Ratings Date), certain covenants will be modified as set forth in the RCF. In addition, prior to Investment Grade Ratings Date, the Company will be required to comply with a maximum consolidated leverage ratio of 3.25x and a minimum consolidated interest coverage ratio of 2.50x. From and after the Investment Grade Ratings Date, the Company will be required to comply with a maximum ratio of consolidated total debt to consolidated total capitalization of 60%. Borrowings under the RCF bear interest at rates based on either the "Alternate Base Rate", the "Adjusted Term Secured Overnight Financing Rate (SOFR) Rate", or the "Adjusted Daily Simple SOFR Rate", respectively, plus the "Applicable Rate". The "Alternate Base Rate" of interest is the highest of (a) the Wall Street Journal prime rate in effect on such day, (b) the New York Federal Reserve Bank Rate in effect on such day plus ½ of 1% and (c) the Adjusted Term SOFR Rate for a one month interest period as published two U.S. Government Securities Business Days prior to such day (or if such day is not a U.S. Government Securities Business Day, the immediately preceding U.S. Government Securities Business Day) plus 1%. The "Adjusted Term SOFR Rate" of interest is equal to (a) the Term SOFR Rate for such Interest Period, plus (b) 0.10%. The "Adjusted Daily Simple SOFR Rate" of interest is equal to (a) the Daily Simple SOFR, plus (b) 0.10%. The "Applicable Rate" of interest means, for any day, the applicable rate per annum based upon the ratings of Moody's Investors Service, Inc. and Standard and Poor's Rating Services, respectively. The Company incurred $14.7 million in transaction costs and recorded the amount to "Deferred charges and other assets" in the Consolidated Balance Sheets, which is being amortized to interest expense over the term of the RCF. At December 31, 2024, the Company had no outstanding borrowings under the RCF and $0.4 million of outstanding letters of credit, which reduces the borrowing capacity of the RCF. At December 31, 2024, the interest rate in effect on borrowings under the facility would have been 6.68%. At December 31, 2024, the Company was in compliance with all covenants related to the RCF.

Note F - Financing Arrangements and Debt (Continued)

Debt Offering

On October 3, 2024, the Company closed the public offering of $600.0 million aggregate principal amount of new senior notes that bear interest at a rate of 6.000% per annum and mature on October 1, 2032. The Company has incurred transaction costs of $10.1 million on the issuance of these new notes. The Company will pay interest semi-annually on April 1 and October 1 of each year, beginning April 1, 2025. The proceeds of the $600.0 million notes were used to fund the repurchase and repayment of debt during the fourth quarter of 2024 to achieve a debt-neutral transaction.

Debt Extinguishment

In December 2024, the Company redeemed $79.0 million of the 2027 Notes. The total cost of the debt extinguishment of $1.2 million, consisting of cash costs of $0.8 million and non-cash costs of $0.4 million, is included in “Interest expense, net” on the Consolidated Statements of Operations for the year ended December 31, 2024.

In October 2024, the Company tendered an aggregate $521.1 million of its notes, comprised of: $258.8 million of the 2027 Notes, $200.2 million of the 2028 Notes and $62.1 million of the 2029 Notes. The total cost of the debt extinguishment of $18.2 million, consisting of cash costs of $14.9 million and non-cash costs of $3.3 million, is included in “Interest expense, net” on the Consolidated Statements of Operations for the year ended December 31, 2024.

In May 2024, the Company paid a total of $50.5 million to complete the open market repurchases of $26.5 million aggregate principal of its 2027 Notes and $23.5 million aggregate principal of its 2028 Notes. The total cost of debt extinguishment of $0.9 million, consisting of cash costs of $0.5 million and non-cash costs of $0.4 million, is included in “Interest expense, net” on the Consolidated Statements of Operations for the year ended December 31, 2024.

In November 2023, the Company tendered a total of $249.5 million of its 2027 Notes, 2028 Notes and 2029 Notes, retiring $250.0 million in aggregate principal. The cost of debt extinguishment of $1.3 million is included in “Interest expense, net” on the Consolidated Statement of Operations for the year ended December 31, 2023. There were no additional cash costs related to the November 2023 debt extinguishment on the 2027 Notes, 2028 Notes and 2029 Notes for the year ended December 31, 2023.

In September 2023, the Company redeemed the remaining $248.7 million principal outstanding of the 2025 Notes. The non-cash costs of debt extinguishment of $0.9 million were included in “Interest expense, net” on the Consolidated Statement of Operations for the year ended December 31, 2023.

Note G – Asset Retirement Obligations

The ARO liabilities recognized by the Company 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 ARO for the respective periods presented is shown in the following table.

(Thousands of dollars)	**2024**	2023
Balance at beginning of year	**$ 914,763**	$ 911,653
Accretion	**52,511**	46,059
Liabilities incurred	**25,619**	20,628
Revisions of previous estimates	**29,279**	29,056
Liabilities settled	**(1,898)**	(95,637)
Changes due to translation of foreign currencies	**(11,390)**	3,004
Balance at end of period	**1,008,884**	914,763
Current portion of liability	**(48,080)**	(10,712)
Non-current portion of liability	**$ 960,804**	$ 904,051

Note G - Asset Retirement Obligations (Continued)

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 H – 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)	**2024**	2023	2022
Income (loss) from continuing operations before income taxes			
United States	**$ 468,202**	$ 901,761	$ 1,306,200
Foreign	**99,367**	19,308	144,061
Total	**$ 567,569**	$ 921,069	$ 1,450,261
Income tax expense (benefit)			
U.S. Federal – Current	**$ —**	$ —	$ —
– Deferred	**55,377**	170,115	234,749
Total U.S. Federal	**55,377**	170,115	234,749
State	**(4,488)**	6,622	9,010
Foreign – Current	**4,685**	13,182	18,134
– Deferred	**22,698**	6,002	47,571
Total Foreign	**27,383**	19,184	65,705
Total	**$ 78,272**	$ 195,921	$ 309,464

The following table reconciles income taxes based on the U.S. statutory tax rate to the Company's income tax expense for each of the three years presented.

(Thousands of dollars)	**2024**	2023	2022
Income tax expense based on the U.S. statutory tax rate	**$ 119,190**	$ 193,424	$ 304,555
Foreign income subject to foreign tax rates different than the U.S. statutory rate	**12,119**	7,597	10,823
State income taxes, net of federal benefit	**(3,568)**	4,725	7,118
U.S. tax benefit on certain foreign upstream investments	**(33,677)**	—	—
Change in deferred tax asset valuation allowance related to other foreign exploration expenditures	**2,636**	10,853	24,748
Tax effect on income attributable to noncontrolling interest	**(16,656)**	(13,046)	(36,471)
Other, net	**(1,772)**	(7,632)	(1,309)
Total	**$ 78,272**	$ 195,921	$ 309,464

Note H – Income Taxes (Continued)

An analysis of the Company’s deferred tax assets and deferred tax liabilities for the respective periods presented showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	**2024**	2023
Deferred tax assets		
Property and leasehold costs	**$ 225,379**	$ 240,065
Liabilities for dismantlements	**36,719**	34,258
Postretirement and other employee benefits	**66,293**	82,437
U. S. net operating loss	**289,594**	357,490
Investment in partnership	**9,096**	14,655
Other deferred tax assets	**100,352**	48,778
Total gross deferred tax assets	**727,433**	777,683
Less: Valuation allowance	**(149,498)**	(146,861)
Net deferred tax assets	**577,935**	630,822
Deferred tax liabilities		
Deferred tax on undistributed foreign earnings	**(5,000)**	(5,000)
Accumulated depreciation, depletion and amortization	**(811,178)**	(847,981)
Other deferred tax liabilities	**(97,547)**	(54,052)
Total gross deferred tax liabilities	**(913,725)**	(907,033)
Net deferred tax (liabilities) assets	**$ (335,790)**	$ (276,211)

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 relates 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 $2.6 million in 2024, 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 a U.S. net operating loss carryforward of $1.4 billion at year-end 2024 with a corresponding deferred tax asset of $289.6 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, 2024, $1.5 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 “Other taxes payable” and “Deferred credits and other liabilities” in the Consolidated Balance Sheets for current and long-term portions, respectively. 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.

Note H – Income Taxes (Continued)

(Thousands of dollars)	**2024**	2023	2022
Balance at January 1	**$ 6,384**	$ 3,928	$ 2,903
Additions for tax positions related to current year	**1,643**	—	77
Additions for tax positions related to prior year	**1,952**	2,456	948
Balance at December 31	**$ 9,979**	$ 6,384	$ 3,928

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 of $0.3 million as of December 31, 2024, 2023 and 2022, respectively, for interest and penalties associated with uncertain tax positions. There were no interest or penalties associated with uncertain tax positions included in income tax expense for any period presented.

In 2025, the Company currently does not expect to add to the provision for uncertain tax positions. Although existing liabilities could be reduced by settlement with taxing authorities or due to statute of limitations closing, 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 2025.

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, 2024, 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 – 2017. The Company has retained certain possible liabilities and rights to income tax receivables relating to Malaysia for the years prior to 2019.

Note I – 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 cash-settled equity awards that are required to be accounted for under liability accounting rules, costs are recognized as expense using a fair value-based measurement method over the vesting period, but expense is adjusted as necessary through the date the award value is finally determined. Total expense for liability awards is ultimately adjusted to the final intrinsic value for the award.

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

The AIP authorizes the 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 AIP are determined based on the Company's actual financial and operating results as measured against the performance goals established by the Committee.

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), SARs, restricted stock, RSUs, 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, 1.2 million shares are available for grant under the 2020 Long-Term Plan at December 31, 2024.

The Company also has a Stock Plan for Non-Employee Directors (NEDs) that permits the issuance of RSUs and stock options or a combination thereof to the Company's NEDs.

Note I – Incentive Plans (Continued)

The Company currently has outstanding incentive awards issued to Directors under the 2021 Stock Plan for NEDs (2021 NED Plan) and the 2018 Stock Plan for NEDs. 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 the vesting of restricted stock and RSUs.

Amounts recognized in the financial statements with respect to share-based plans for each of the three years presented are shown in the following table.

(Thousands of dollars)	**2024**	2023	2022
Compensation charged against income before income tax benefit	**$ 40,831**	$ 58,760	$ 74,587
Related income tax benefit recognized in income	**5,513**	9,330	12,710

As of December 31, 2024, there were $46.9 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 RSU vest.

Equity-Settled Awards

PERFORMANCE-BASED RESTRICTED STOCK UNITS – PSUs to be settled in common shares were granted in 2022, 2023 and 2024 under the 2020 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 the recognized compensation cost associated with the stock award would not be reversed. The performance conditions for the PSUs are weighted 80% on the Company's total shareholder return (TSR) relative to an industry peer group and 20% on the return on average capital employed (ROACE), measured over the applicable performance period. ROACE is calculated by dividing the Company's EBITDA by the average of the opening and closing Capital Employed (the sum of total equity and short-term and long-term debt). 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.

The fair value of the PSUs based on the Company's TSR 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 performance measurement 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 2024, 2023 and 2022 are presented in the following table.

	2024	2023	2022
Fair value per share at grant date	**$41.95**	$60.46	$37.77 - $47.37
Assumptions			
Expected volatility	**50.00%**	81.00%	79.00% - 81.00%
Risk-free interest rate	**4.14%**	3.90%	1.39% - 2.85%
Stock beta	**1.062**	1.034	1.195 - 1.200
Expected life	**3.0 years**	3.0 years	3.0 years

The fair value of the PSUs based on ROACE was estimated based on the average high/low price of the Company's stock on the grant date.

Note I – Incentive Plans (Continued)

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

(Number of stock units)	**2024**	2023	2022
Outstanding at beginning of year	**1,818,188**	2,148,467	2,670,756
Granted	**536,900**	409,160	595,700
Vested and issued	**(938,599)**	(408,135)	(654,177)
Forfeited	**(24,068)**	(331,304)	(463,812)
Outstanding at end of year	**1,392,421**	1,818,188	2,148,467

TIME-BASED RESTRICTED STOCK UNITS – Time-based RSUs have been granted to the Company's NEDs under the 2021 NED Plan, and to certain employees under the 2020 Long-Term Plan.

The fair value of the time-based RSUs awarded for each of the last three years is presented in the following table.

Type of Plan	**Valuation Methodology**	**2024**	2023	2022
Non-Employee Directors [1]	Closing Stock Price at Grant Date	**\$30.26 - \$45.70**	\$43.27	\$32.84
Long-Term Incentive Plan [2]	Average High/Low Stock Price at Grant Date	**\$37.78 - \$45.98**	\$42.20	\$29.80 - \$49.86

[1] Under the 2021 NED Plan, RSUs granted in 2024 are scheduled to vest in February 2025.

[2] The RSUs granted under the 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)	**2024**	2023	2022
Outstanding at beginning of year	**1,219,584**	1,227,792	1,451,438
Granted	**741,228**	556,100	416,492
Vested and issued	**(330,444)**	(517,047)	(462,418)
Forfeited	**(71,768)**	(47,261)	(177,720)
Outstanding at end of year	**1,558,600**	1,219,584	1,227,792

STOCK OPTIONS – In 2017, the Company ceased the inclusion of stock options and SARs as a part of the long-term incentive compensation mix. As of December 31, 2023 there were no outstanding stock options. As of December 31, 2024, there were no outstanding SARs.

Prior to 2017, 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 Incentive 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.

Note I – Incentive Plans (Continued)

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, 2021	1,319,500	$ 37.77
Exercised	(760,500)	23.29
Forfeited	(546,000)	49.65
Outstanding at December 31, 2022	13,000	28.51
Exercised	(11,000)	28.51
Forfeited	(2,000)	28.51
Outstanding at December 31, 2023	**—**	—
Exercisable at December 31, 2021	1,319,500	34.25
Exercisable at December 31, 2022	13,000	28.51

Cash-Settled Awards

The Company has granted phantom stock-based incentive awards to be settled in cash to certain employees in the form of SARs and CRSUs.

SAR awards have terms similar to stock options. CRSUs generally settle on the third anniversary of the date of grant. Each award granted is settled, net of applicable income tax withholdings, in cash rather than with common shares. Total pretax expense recorded in the Consolidated Statements of Operations for all cash-settled stock-based awards was $1.7 million in 2024, $29.4 million in 2023 and $49.3 million in 2022.

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 $37.1 million, $30.9 million and $42.9 million was recorded in 2024, 2023 and 2022, respectively, for these plans.

Note J – 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. refining and marketing 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 Sheets and to recognize changes in that funded status between periods through "Accumulated other comprehensive loss".

The tables that follow provide a reconciliation of the changes in the plans' benefit obligations, fair value of assets and funded status for the respective periods presented.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note J – Employee and Retiree Benefit Plans (Continued)

(Thousands of dollars)	Pension Benefits		Other Postretirement Benefits	
	2024	2023	**2024**	2023
Change in benefit obligation				
Obligation at January 1	**$ 699,151**	$ 663,073	**$ 63,808**	$ 67,679
Service cost	**7,042**	6,542	**436**	495
Interest cost	**33,554**	34,140	**2,923**	3,241
Participant contributions	**—**	—	**2,730**	2,629
Actuarial (gain) loss [1]	**(35,417)**	26,625	**825**	(5,567)
Medicare Part D subsidy	**—**	—	**358**	299
Exchange rate changes	**(3,263)**	6,089	**(14)**	2
Benefits paid	**(45,743)**	(56,296)	**(16,072)**	(4,970)
Plan amendments [2]	**—**	18,978	**—**	—
Obligation at December 31	**655,324**	699,151	**54,994**	63,808
Change in plan assets				
Fair value of plan assets at January 1	**477,809**	450,944	**—**	—
Actual return on plan assets	**27,317**	39,953	**—**	—
Employer contributions	**35,477**	37,546	**12,984**	2,042
Participant contributions	**—**	—	**2,730**	2,629
Medicare Part D subsidy	**—**	—	**358**	299
Exchange rate changes	**(2,740)**	5,662	**—**	—
Benefits paid	**(45,743)**	(56,296)	**(16,072)**	(4,970)
Fair value of plan assets at December 31	**492,120**	477,809	**—**	—
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	**1,819**	3,192	**—**	—
Other accrued liabilities	**(10,617)**	(10,219)	**(4,237)**	(4,433)
Deferred credits and other liabilities	**(154,406)**	(214,315)	**(50,757)**	(59,375)
Fund Status and net plan liability recognized at December 31	**$ (163,204)**	$ (221,342)	**$ (54,994)**	$ (63,808)

[1] Actuarial gains in 2024 primarily relate to the increase in the discount rate assumption, which decreases the pension benefit obligation.

[2] At December 31, 2023, the Company recognized an increase to its domestic plan benefit obligation related to a plan amendment. The amendment provides a permanent increase to benefits for retirees and beneficiaries who commenced payments prior to 2020.

At December 31, 2024, amounts included in “Accumulated other comprehensive loss” 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)	$ (163,218)	$ 39,742
Prior service (credit) cost	(18,233)	3,405
	$ (181,451)	$ 43,147

Note J – Employee and Retiree Benefit Plans (Continued)

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)	**2024**	2023	**2024**	2023	**2024**	2023
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	**$ 497,947**	$ 534,751	**$ 489,225**	$ 523,096	**$ 477,983**	$ 461,363
Unfunded nonqualified and directors' plans where accumulated benefit obligation exceeds fair value of plan assets	**145,058**	151,146	**143,859**	148,661	**—**	—
Unfunded other postretirement plans	**54,994**	63,808	**54,994**	63,808	**—**	—

The table that follows provides the components of net periodic benefit expense for each of the three years presented.

	Pension Benefits			Other Postretirement Benefits		
(Thousands of dollars)	**2024**	2023	2022	**2024**	2023	2022
Service cost	**$ 7,042**	$ 6,542	$ 7,875	**$ 436**	$ 495	$ 968
Interest cost	**33,554**	34,140	22,747	**2,923**	3,241	2,211
Expected return on plan assets	**(33,427)**	(32,839)	(36,458)	**—**	—	—
Amortization of prior service cost (credit)	**2,316**	620	(684)	**(532)**	(532)	(532)
Recognized actuarial loss (gain)	**9,438**	9,776	16,098	**(3,586)**	(3,512)	(615)
Net periodic benefit expense	**18,923**	18,239	9,578	**(759)**	(308)	2,032
Other pension costs	**251**	219	—	**—**	—	—
Total net periodic benefit expense	**$ 19,174**	$ 18,458	$ 9,578	**$ (759)**	$ (308)	$ 2,032

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

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2024**	2023	**2024**	2023
Benefit obligation at December 31	**$ 115,428**	$ 133,822	**$ 106**	$ 115
Fair value of plan assets at December 31	**103,445**	119,236	**—**	—
Net plan liabilities recognized	**(11,983)**	(14,586)	**(106)**	(115)
Net periodic benefit expense (benefit)	**1,480**	1,387	**(44)**	(44)

Note J – Employee and Retiree Benefit Plans (Continued)

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2024 and 2023 and net periodic benefit expense for 2024 and 2023.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,		Year		Year	
	2024	2023	**2024**	2023	**2024**	2023	**2024**	2023
Discount rate on obligation, interest cost and service cost	**5.58 %**	5.03 %	**5.65 %**	5.15 %	**5.17 %**	5.27 %	**5.15 %**	5.41 %
Rate of compensation increase	**3.38 %**	3.52 %	**—**	—	**3.50 %**	3.52 %	**—**	—
Cash balance interest credit rate	**3.20 %**	3.20 %	**—**	—	**—**	—	**—**	—
Expected return on plan assets	**—**	—	**—**	—	**7.19 %**	7.35 %	**—**	—

The discount rates used for determining the plan obligations and expense are based on 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. The plan's cash balance interest accumulation rate is the greater of the annual yield on 10-year treasury constant maturities or 1.89%.

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
2025	$ 49,406	$ 4,237
2026	50,193	4,252
2027	51,634	4,267
2028	51,632	4,386
2029	51,457	4,278
2030-2034	261,891	20,594

For purposes of measuring postretirement benefit obligations at December 31, 2024, the future annual rates of increase in the cost of health care were assumed to be 7.5% for 2025 decreasing each year to an ultimate rate of 4.0% in 2048 and thereafter.

During 2024, the Company made contributions of $34.7 million to its domestic defined benefit pension plans and $13.0 million to its domestic postretirement benefits plan. During 2025, the Company currently expects to make contributions of $25.6 million to its domestic defined benefit pension plans, $0.8 million to its foreign defined benefit pension plans and $4.2 million to its domestic postretirement benefits plan.

PLAN INVESTMENTS – Murphy Oil Corporation maintains an Investment Policy Statement (Statement) that establishes investment standards related to its funded domestic qualified retirement plan. 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 issued 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 40-75% equity securities, 20-60% fixed income securities, 0-15% alternatives and 0-20% 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 the respective balance sheet dates are shown in the following table.

	December 31,	
	2024	2023
Equity securities	**57.3 %**	62.6 %
Fixed income securities	**36.2 %**	29.1 %
Alternatives	**3.7 %**	5.1 %
Cash equivalents	**2.8 %**	3.2 %
	100.0 %	100.0 %

The Company's weighted average expected return on plan assets was 7.2% in 2024 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 7.2% expected return was comprised of the weighted average expected future equity securities return of 8.0% and a fixed income securities return of 5.2%. An average expected investment expense of 0.8% is included in this calculation. Over the last 10 years, the return on funded retirement plan assets has averaged 3.3%.

At December 31, 2024, 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, 2024	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	**$ 87,124**	**$ 87,124**	**$ —**	**$ —**
U.S. small/midcap	**51,978**	**51,978**	**—**	**—**
Other alternative strategies	**965**	**—**	**—**	**965**
International equity	**22,724**	**22,724**	**—**	**—**
Emerging market equity	**7,638**	**7,638**	**—**	**—**
Fixed income securities:				
U.S. fixed income	**208,755**	**105,302**	**103,453**	**—**
Cash and equivalents	**9,491**	**9,491**	**—**	**—**
Total Domestic Plans	**388,675**	**284,256**	**103,453**	**965**
Foreign Plans				
Equity securities funds	**14,377**	**—**	**14,377**	**—**
Fixed income securities funds	**26,500**	**—**	**26,500**	**—**
Diversified pooled fund	**41,054**	**—**	**41,054**	**—**
Other	**17,049**	**—**	**—**	**17,049**
Cash and equivalents	**4,465**	**—**	**4,465**	**—**
Total Foreign Plans	**103,445**	**—**	**86,396**	**17,049**
Total	**$ 492,120**	**$ 284,256**	**$ 189,849**	**$ 18,014**

Note J – Employee and Retiree Benefit Plans (Continued)

At December 31, 2023, 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, 2023	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	$ 105,212	$ 105,212	$ —	$ —
U.S. small/midcap	64,165	64,165	—	—
Other alternative strategies	3,831	—	—	3,831
International equity	31,820	31,820	—	—
Emerging market equity	10,525	10,525	—	—
Fixed income securities:				
U.S. fixed income	132,608	56,381	76,227	—
Cash and equivalents	10,412	10,412	—	—
Total Domestic Plans	358,573	278,515	76,227	3,831
Foreign Plans				
Equity securities funds	24,389	—	24,389	—
Fixed income securities funds	23,930	—	23,930	—
Diversified pooled fund	45,162	—	45,162	—
Other	20,623	—	—	20,623
Cash and equivalents	5,133	—	5,133	—
Total Foreign Plans	119,236	—	98,613	20,623
Total	$ 477,809	$ 278,515	$ 174,841	$ 24,454

The definition of levels within the fair value hierarchy in the tables above is included in Note O.

For domestic plans, U.S. core, small/midcap, international, emerging market equity securities and U.S. treasury securities are valued based on 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 two investments. One of these investments is valued annually based on net asset value and permits withdrawals annually after a 90-day notice, and the other investment is valued quarterly based on net asset values and has a three-year lock-up period and a 95-day notice following the lock-up period. The latter of these investments was sold during 2024.

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.

Note J – Employee and Retiree Benefit Plans (Continued)

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, 2022	$ 32,734
Actual return on plan assets:	
Relating to assets held at the reporting date	711
Purchases, sales and settlements	(8,991)
Total at December 31, 2023	24,454
Actual return on plan assets:	
Relating to assets held at the reporting date	**(3,574)**
Relating to assets sold during the period	**(2,865)**
Total at December 31, 2024	**$ 18,015**

401(K) PLANS - Most full-time U.S. employees of the Company may participate in a 401(k) 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 6.0%. Amounts charged to expense for the Company's match to these plans were $8.7 million in 2024, $8.5 million in 2023 and $6.0 million in 2022.

Note K – 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 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.

Commodity Price Risks

The Company is subject to commodity price risk related to products it produces and sells. During 2024, the Company entered into natural gas swap contracts that will be effective in 2025. Under the swap 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.

At December 31, 2024 volumes per day associated with outstanding natural gas derivative contracts and the weighted average prices for these contracts are as follows:

NYMEX Henry Hub	Area	Commodity	Volumes MMCF/d	Price/MCF	Start Date	End Date
Fixed price derivative swap	United States	Natural gas	20	$ 3.20	1/1/2025	1/31/2025

Subsequent to year end, the Company entered into additional natural gas derivative contracts. Volumes per day and the weighted average prices for these contracts are as follows:

NYMEX Henry Hub	Area	Commodity	Volumes MMCF/d	Price/MCF	Start Date	End Date
Fixed price derivative swap	United States	Natural gas	40	$ 3.58	2/1/2025	6/30/2025
Fixed price derivative swap	United States	Natural gas	60	$ 3.65	7/1/2025	9/30/2025
Fixed price derivative swap	United States	Natural gas	60	$ 3.74	10/1/2025	12/31/2025

At December 31, 2023 the Company did not have any outstanding crude oil or natural gas derivative contracts.

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, 2024 and 2023.

At December 31, 2024 and 2023, the fair value of derivative instruments not designated as hedging instruments are presented in the following table. See also Note O.

(Thousands of dollars)	Asset (Liability) Derivatives Fair Value at December 31,		
Type of Derivative Contract	**Balance Sheet Location**	**2024**	2023
Commodity swaps	Accounts payable	**$ (1,707)**	—

The gains and losses recognized in the Consolidated Statements of Operations for derivative instruments not designated as hedging instruments for each of the three years presented are shown in the following table.

		Gain (Loss)		
(Thousands of dollars)		**Year Ended December 31,**		
Type of Derivative Contract	**Statement of Operations Locations**	**2024**	2023	2022
Commodity swaps	Loss on derivative instruments	**$ (1,707)**	$ —	$ (160,690)
Commodity collars	Loss on derivative instruments	**—**	—	(159,721)

Credit Risks

The Company is subject to credit risks primarily 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 associated with 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 L – Net Income (Loss) Per Common Share

Net income (loss) attributable to Murphy was used as the numerator in computing both basic and diluted income per common share for each of the three years presented. The following table reconciles the weighted-average shares outstanding used for these computations.

(Weighted-average shares)	**2024**	2023	2022
Basic method	**150,011,458**	155,233,560	155,276,533
Dilutive stock options and restricted stock units	**1,015,894**	1,412,869	2,198,305
Diluted method	**151,027,352**	156,646,429	157,474,838

The following table reflects certain options to purchase shares of common stock that were outstanding during each of the three years presented but were not included in the computation of diluted earnings per share because the incremental shares from the assumed conversion were antidilutive.

	2024	2023	2022
Antidilutive stock options excluded from diluted shares	**—**	—	126,000
Weighted average price of these options	**—**	—	$49.65

Note M – 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 $45.4 million gain in 2024, $10.8 million loss in 2023 and $23.0 million gain in 2022.

Supplemental Information to Statement of Cash Flows

(Thousands of dollars)	**2024**	2023	2022
Net (increase) decrease in operating working capital, excluding cash and cash equivalents:			
(Increase) decrease in accounts receivable	**$ 71,081**	$ 47,151	$ (137,228)
(Increase) decrease in inventories	**1,327**	329	(1,534)
(Increase) decrease in prepaid expenses	**1,192**	(1,293)	(3,413)
Increase (decrease) in accounts payable and accrued liabilities [1]	**3,287**	(140,011)	69,854
Increase (decrease) in income taxes payable	**(2,004)**	(5,537)	6,593
Net decrease (increase) in non-cash operating working capital	**$ 74,883**	$ (99,361)	$ (65,728)
Supplementary disclosures:			
Cash income taxes paid, net of refunds	**$ 12,648**	$ 12,356	$ 24,853
Interest paid, net of amounts capitalized of $11.4 million in 2024, $14.5 million in 2023 and $16.3 million in 2022	**78,806**	108,912	149,597
Non-cash investing activities:			
Asset retirement costs capitalized	**$ 47,233**	$ 32,975	$ (21,147)
(Increase) decrease in capital expenditure accrual	**(5,935)**	17,517	(31,397)

[1] Excludes receivable/payable balances relating to mark-to-market of derivative instruments.

Note N – Accumulated Other Comprehensive Loss

The components of ”Accumulated other comprehensive loss” on the Consolidated Balance Sheets for the periods presented and the changes during the respective periods are shown net of taxes in the following table.

(Thousands of dollars)	**Foreign Currency Translation Gains (Losses)**	**Retirement and Postretirement Benefit Plan Adjustments**	**Total**
Balance at December 31, 2022	$ (418,230)	$ (116,456)	$ (534,686)
2023 components of other comprehensive income (loss):			
Before reclassifications to income	36,598	(27,580)	9,018
Reclassifications to income	—	4,551 [1]	4,551
Net other comprehensive income	36,598	(23,029)	13,569
Balance at December 31, 2023	(381,632)	(139,485)	(521,117)
2024 components of other comprehensive income (loss):			
Before reclassifications to income	**(134,692)**	**23,713**	**(110,979)**
Reclassifications to income	**—**	**4,024** [1]	**4,024**
Net other comprehensive income (loss)	**(134,692)**	**27,737**	**(106,955)**
Balance at December 31, 2024	**$ (516,324)**	**$ (111,748)**	**$ (628,072)**

[1] Reclassifications before taxes of $5.4 million and $5.6 million are included in the computation of net periodic benefit expense in 2024 and 2023, respectively. See Note J for additional information. Related income taxes of $1.4 million and $1.1 million are included in income tax expense in 2024 and 2023, respectively.

Note O – 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 for the respective periods presented are shown in the following table.

	December 31, 2024				December 31, 2023			
(Thousands of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Liabilities:								
Nonqualified employee savings plan	**$ 19,469**	**$ —**	**$ —**	**$ 19,469**	$ 17,785	$ —	$ —	$ 17,785
Commodity swaps	**—**	**1,707**	**—**	**1,707**	—	—	—	—
	$ 19,469	**$ 1,707**	**$ —**	**$ 21,176**	$ 17,785	$ —	$ —	$ 17,785

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 commodity swaps liability as of December 31, 2024 was $1.7 million and recorded as “Accounts payable” in the Consolidated Balance Sheets. The fair value of the commodity swaps was based on active market quotes for NYMEX Henry Hub natural gas. The before tax income effect of changes in fair value of natural gas derivative contracts is recorded in “(Loss) Gain on derivative instruments” in the Consolidated Statements of Operations.

The Company acquired Gulf of America assets from LLOG Exploration Offshore L.L.C. and LLOG Bluewater Holdings, L.L.C. (collectively, LLOG) and, in a separate agreement, from Petrobras America Inc. (PAI) in 2019 and 2018, respectively. Under the terms of both transactions, contingent consideration was paid after meeting specified revenue thresholds and project milestones and recorded to “Contingent consideration payment” in the Consolidated Statements of Cash Flows.

As at December 31, 2022, the Company’s liabilities with PAI and LLOG were based on realized inputs of volumes and pricing as a result of contractual thresholds and time durations being achieved. As a result, the related liability as at December 31, 2022, of $192.7 million, was no longer subject to fair value measurement. The liability was included in “Other accrued liabilities” in the Consolidated Balance Sheets and the changes in fair value of the contingent consideration during 2022 were recorded in “Other income (loss)” 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, 2024 and 2023.

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2024 and 2023. 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. Substantially all of the Company’s long-term debt is actively traded in open markets, and accordingly, is classified as Level 1 in the fair value hierarchy. 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.

Note O – Assets and Liabilities Measured at Fair Value (Continued)

	December 31,							
	2024				2023			
(*Thousands of dollars*)	**Carrying Amount**		**Fair Value**		Carrying Amount		Fair Value	
Financial liabilities:								
Current and long-term debt	**$**	**1,275,374**	**$**	**1,185,961**	$	1,329,075	$	1,265,185

Fair Values – Nonrecurring

Impairment expenses of $62.9 million were incurred in 2024. In the first quarter of 2024, an impairment charge of $34.5 million was triggered for the Calliope field, and in the fourth quarter of 2024, an impairment charge of $28.4 million was triggered for the Nearly Headless Nick field. Both of the impairments were due to operational issues that led to reserve reductions.

There were no impairment expenses incurred in 2023.

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 the impaired properties is presented in the following table:

	Year Ended December 31, 2024					
	Fair Value					
(*Thousands of dollars*)	Level 1		Level 2	Level 3	Net Book Value Prior to Impairment	Total Pretax Impairment
2024						
Assets:						
Impaired proved properties						
United States - Offshore	$	—	—	501	63,410	62,909

Note P – Commitments

The Company has operating, production handling and transportation service agreements for oil and/or natural gas operations in the U.S. and Canada Onshore. The U.S. Onshore and U.S. Offshore transportation contracts require minimum monthly payments through 2045, while the Canada Onshore transportation contracts call for minimum monthly payments through 2051. In the U.S. and Canada Onshore, future required minimum annual payments for the next five years are $148.8 million in 2025, $117.7 million in 2026, $105.5 million in 2027, $96.0 million in 2028 and $64.2 million in 2029. 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 $225.9 million in 2024, $295.1 million in 2023 and $216.4 million in 2022.

Commitments for capital expenditures were approximately $417.0 million at December 31, 2024, including $53.6 million for the Gulf of America, $112.2 million for Eagle Ford Shale, $31.2 million for Canada and $220.0 million for Other Offshore, mainly for capital projects in Vietnam.

Commitments for operating agreements include approximately $178.0 million at December 31, 2024 for Other Offshore for the purpose of supporting future development activities in Vietnam.

Note Q – 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, regulations and government action intended for the promotion of safety and the protection and/or remediation of the environment including in connection with the purported causes or potential impacts of climate change; governmental support for other forms of energy; and laws and regulations affecting the Company's relationships with employees, suppliers, customers, stockholders and others. Given the factors involved in various government actions, including political considerations, it is difficult to predict their likelihood, the form they may take, or the effect they 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 and protection of health and safety. 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 methane and other GHG emissions; wildlife, habitat and water protection; water access, use and disposal; the placement, operation and decommissioning of production equipment; the health and safety of our employees, contractors and communities where our operations are located, including indigenous communities; and the causes and impacts of climate change. 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.

Violation of federal or state environmental, health and safety 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 adequately 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. In addition, 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 and the Company is not aware of environmental legal proceedings likely to exceed this $1.0 million threshold.

There continues to be an increase in regulatory oversight of the oil and gas industry at the federal level, with a focus on climate change and GHG emissions (including methane emissions). For example, in March 2024, the U.S. EPA published its final rule regulating methane and volatile organic compounds emissions in the oil and gas industry which, among other things, requires periodic inspections to detect leaks (and subsequent repairs), places stringent restrictions on venting and flaring of methane, and establishes a program whereby third parties can monitor and report large methane emissions to the U.S. EPA. In November 2024, the U.S. EPA published its final rule implementing a charge on large emitters of waste methane from the oil and gas sector. The charge, referred to as the WEC, is a component of the Biden Administration's Methane Emissions Reduction Program to limit methane emissions from the oil and gas industry under the 2022 IRA. Executive orders have also been issued related to oil and gas activities on federal lands, infrastructure and environmental justice. In addition, an international climate agreement (the Paris Agreement) was agreed to at the 2015 United Nations Framework Convention on Climate Change in Paris, France. Although the U.S. officially withdrew from the Paris Agreement on November 4, 2020, the U.S. rejoined the Paris Agreement, which became effective for the U.S. on February 19, 2021. In January 2025, the United States submitted formal notification to the United Nations that it intends to withdraw from the Paris Agreement again. Pursuant to the terms of the Paris Agreement, the withdrawal will take effect on January 27, 2026.

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. Depending on the evolution of laws, regulations and litigation outcomes relating to climate change, there can be no guarantee that climate change litigation will not in the future materially adversely affect our results of operations, cash flows and financial condition.

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 (including litigation related to climate change), 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 R – Common Stock Issued and Outstanding

Activity in the number of shares of common stock issued and outstanding for each of the three years presented is shown below.

(*Number of shares outstanding*)	**2024**	2023	2022
Beginning of year	**152,748,642**	155,467,319	154,463,050
Stock options exercised [1]	**—**	2,657	181,655
Restricted stock awards [1]	**1,105,268**	689,824	822,614
Treasury shares purchased	**(8,008,786)**	(3,411,158)	—
End of year	**145,845,124**	152,748,642	155,467,319

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

The Company's Board of Directors has authorized a share repurchase program whereby the Company can repurchase up to $1,100.0 million of its common stock. This repurchase program has no time limit and may be suspended or discontinued completely at any time without prior notice as determined by the Company at its discretion and dependent upon a variety of factors.

During the year ended December 31, 2024, the Company repurchased 8.0 million shares of its common stock under the share repurchase program for $300.0 million ($302.7 million including excise taxes and fees). As of December 31, 2024, the Company had $650.1 million of its common stock remaining available to repurchase under the program.

Subsequent to year end, as of February 25, 2025, the Company repurchased 3.4 million shares of its common stock in open-market transactions for $95.1 million, excluding taxes and fees. As of this date, the Company had $555.0 million of its common stock remaining available to repurchase under the program.

The share repurchase program is a component of the Company's capital allocation framework, the details of which can be found as part of the Company's Form 8-K filed on August 4, 2022 and Form 8-K filed on August 8, 2024.

Note S – 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 U.S., Canada and all other countries. Each of these segments derive revenues primarily from the sale of crude oil, NGLs and/or natural gas. The Company's management team and Chief Operating Decision Maker (CODM) evaluates segment performance-based on income (loss) from operations, excluding interest income and interest expense, and allocates financial and capital resources for each segment predominantly in the annual budget and forecasting process. The CODM also considers budget-to-actual variances on a monthly basis for the performance measure when making decisions about allocating capital and personnel to the segments.

For the income statement periods presented in these financial statements, Murphy's former CEO, Roger Jenkins, acted as the CODM. As of January 1, 2025, Murphy appointed a new CEO, Eric Hambly.

Customers that accounted for 10% or more of the Company's sales revenue for each of the below three years ended December 31, are shown below.

	2024	2023	2022
Chevron Corporation	**13 %**	16 %	19 %
ExxonMobil Corporation	**20 %**	27 %	12 %
Phillips 66	**10 %**	N/A	N/A

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.

No assets were held for sale as of December 31, 2024 and 2023. The former U.K., Malaysia and U.S. refining and marketing units have been reported as discontinued operations for all periods presented in these consolidated financial statements.

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 and natural gas contracts), interest expense and unallocated overhead, are shown in the tables to reconcile the business segments to consolidated totals.

"Other segment costs" below are those items that are included in Segment income (loss) but are not regularly provided to the CODM, or are reported to the CODM but are not considered to be significant segment expenses. "Other segment costs" for the years presented included certain pension amortization costs allocated to the reportable segments, and dividend income from short-term investment accounts attributed to the Canada segment.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note S – Business Segments (Continued)

	Exploration and Production					
(Millions of dollars)	United States [1]	Canada	Other	Total E&P	Corporate, Other, and Discontinued Operations	Consolidated Total
Year ended December 31, 2024						
Revenue from production	$ 2,503.8	$ 504.5	$ 6.6	$ 3,014.9	$ —	$ 3,014.9
Sales of purchased natural gas	—	3.7	—	3.7	—	3.7
Gain on sales of assets and other operating income	4.5	1.5	—	6.0	3.9	9.9
Revenues from external customers	2,508.3	509.7	6.6	3,024.6	3.9	3,028.5
Lease operating expenses						
Lease operating expenses and taxes other than income	471.3	176.8	1.6	649.7	—	649.7
Repair and maintenance	63.7	4.8	—	68.5	—	68.5
Workovers	214.9	3.9	—	218.8	—	218.8
Total lease operating expenses	749.9	185.5	1.6	937.0	—	937.0
Severance and ad valorem taxes	37.8	1.4	—	39.2	—	39.2
Transportation, gathering and processing	130.9	79.9	—	210.8	—	210.8
Costs of purchased natural gas	—	3.1	—	3.1	—	3.1
Selling and general expenses	(3.3)	20.4	6.7	23.8	89.1	112.9
Exploration Expenses					—	
Geological and geophysical	14.4	0.2	12.6	27.2	—	27.2
Dry holes and previously suspended exploration costs	70.9	—	2.3	73.2	—	73.2
Other exploratory costs, including undeveloped lease amortization and delay lease rentals	10.9	0.3	21.9	33.1	—	33.1
Total exploration expenses	96.2	0.5	36.8	133.5	—	133.5
Depreciation, depletion and amortization	709.2	146.0	1.7	856.9	8.9	865.8
Impairment of assets	62.9	—	—	62.9	—	62.9
Accretion of asset retirement obligations	43.1	8.6	0.7	52.4	0.1	52.5
Other operating expenses	9.3	2.8	2.1	14.2	(3.2)	11.0
Interest Income	(22.0)	—	—	(22.0)	(12.2)	(34.2)
Interest (expense), net of capitalization	0.2	0.4	0.2	0.8	105.1	105.9
Income tax expense						
Current income tax expense	1.5	3.2	0.2	4.9	0.9	5.8
Deferred income tax expense	123.8	8.8	(31.2)	101.4	(28.9)	72.5
Total income tax expense	125.3	12.0	(31.0)	106.3	(28.0)	78.3
Other segment costs (income)	6.9	0.1	0.3	7.3	(44.0)	(36.7)
Segment income (loss) - including NCI [1]	$ 561.9	$ 49.0	$ (12.5)	$ 598.4	$ (111.9)	$ 486.5
Additions to property, plant, equipment	$ 601.7	$ 137.9	$ 71.8	$ 811.4	$ 29.2	$ 840.6
Total assets at year-end	6,953.8	1,919.8	302.0	9,175.6	491.9	9,667.5

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

Note S – Business Segments (Continued)

	Exploration and Production					
(Millions of dollars)	United States [1]	Canada	Other	Total E&P	Corporate, Other, and Discontinued Operations	Consolidated Total
Year ended December 31, 2023						
Revenue from production	$ 2,921.8	$ 443.8	$ 11.0	$ 3,376.6	$ —	$ 3,376.6
Sales of purchased natural gas	—	72.2	—	72.2	—	72.2
Gain on sales of assets and other operating income	6.5	1.5	—	8.0	3.3	11.3
Revenues from external customers	2,928.3	517.5	11.0	3,456.8	3.3	3,460.1
Lease operating expenses						
Lease operating expenses and taxes other than income	532.3	144.7	1.9	678.9	—	678.9
Repair and maintenance	53.2	5.0	—	58.2	—	58.2
Workovers	45.2	2.1	—	47.3	—	47.3
Total lease operating expenses	630.7	151.8	1.9	784.4	—	784.4
Severance and ad valorem taxes	41.4	1.4	—	42.8	—	42.8
Transportation, gathering and processing	157.0	76.0	—	233.0	—	233.0
Costs of purchased natural gas	—	51.7	—	51.7	—	51.7
Selling and general expenses	11.8	16.5	9.4	37.7	81.2	118.9
Exploration Expenses					—	
Geological and geophysical	6.6	0.1	19.4	26.1	—	26.1
Dry holes and previously suspended exploration costs	153.1	—	16.7	169.8	—	169.8
Other exploratory costs, including undeveloped lease amortization and delay lease rentals	14.9	0.4	23.6	38.9	—	38.9
Total exploration expenses	174.6	0.5	59.7	234.8	—	234.8
Depreciation, depletion and amortization	706.0	142.2	2.3	850.5	11.0	861.5
Accretion of asset retirement obligations	37.8	7.8	0.4	46.0	0.1	46.1
Other operating expenses						
Other miscellaneous operating expenses	20.1	15.5	8.1	43.7	(4.4)	39.3
Loss on contingent consideration	7.1	—	—	7.1	—	7.1
Total other operating expenses	27.2	15.5	8.1	50.8	(4.4)	46.4
Interest Income	(3.3)	—	—	(3.3)	(9.3)	(12.6)
Interest expense, net of capitalization	0.1	0.2	0.2	0.5	111.9	112.4
Income tax expense						
Current income tax expense	3.1	3.7	0.6	7.4	8.8	16.2
Deferred income tax expense	229.6	7.5	(6.7)	230.4	(50.6)	179.8
Total income tax expense	232.7	11.2	(6.1)	237.8	(41.8)	196.0
Other segment costs (income)	7.2	1.1	0.6	8.9	12.1	21.0
Segment income (loss) - including NCI [1]	$ 905.1	$ 41.6	$ (65.5)	$ 881.2	$ (157.5)	$ 723.7
Additions to property, plant, equipment	$ 671.3	$ 206.2	$ 13.1	$ 890.6	$ 24.2	$ 914.8
Total assets at year-end	7,107.0	2,080.0	213.3	9,400.2	366.5	9,766.7

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note S – Business Segments (Continued)

	Exploration and Production					
(Millions of dollars)	United States [1]	Canada	Other	Total E&P	Corporate, Other, and Discontinued Operations	Consolidated Total
Year ended December 31, 2022						
Revenue from production	$ 3,435.5	$ 580.0	$ 23.0	$ 4,038.5	$ —	$ 4,038.5
Sales of purchased natural gas	0.2	181.5	—	181.7	—	181.7
Gain on sales of assets and other operating income (loss)	25.5	1.4	—	26.9	(314.4)	(287.5)
Revenues from external customers	3,461.2	762.9	23.0	4,247.1	(314.4)	3,932.7
Lease operating expenses						
Lease operating expenses and taxes other than income	458.2	147.9	1.5	607.6	—	607.6
Repair and maintenance	34.9	4.7	—	39.6	—	39.6
Workovers	29.6	2.5	—	32.1	—	32.1
Total lease operating expenses	522.7	155.1	1.5	679.3	—	679.3
Severance and ad valorem taxes	55.7	1.3	—	57.0	—	57.0
Transportation, gathering and processing	142.2	70.5	—	212.7	—	212.7
Costs of purchased natural gas	0.2	171.8	—	172.0	—	172.0
Selling and general expenses	20.4	21.9	2.2	44.5	88.8	133.3
Exploration Expenses					—	
Geological and geophysical	8.3	0.4	1.8	10.5	—	10.5
Dry holes and previously suspended exploration costs	23.0	—	59.1	82.1	—	82.1
Other exploratory costs, including undeveloped lease amortization and delay lease rentals	16.2	0.7	23.7	40.6	—	40.6
Total exploration expenses	47.5	1.1	84.6	133.2	—	133.2
Depreciation, depletion and amortization	617.0	141.5	5.4	763.9	12.9	776.8
Accretion of asset retirement obligations	36.5	9.6	0.1	46.2	—	46.2
Other operating expenses						
Other miscellaneous operating expenses	41.3	10.5	2.4	54.2	5.0	59.2
Loss on contingent consideration	78.3	—	—	78.3	—	78.3
Total other operating expenses	119.6	10.5	2.4	132.5	5.0	137.5
Interest Income	(0.3)	—	—	(0.3)	(2.5)	(2.8)
Interest expense, net of capitalization	0.1	—	0.3	0.4	150.4	150.8
Income tax expense						
Current income tax expense	8.1	8.8	2.3	19.2	4.2	23.4
Deferred income tax expense	362.7	34.8	0.6	398.1	(112.0)	286.1
Total income tax expense	370.8	43.6	2.9	417.3	(107.8)	309.5
Other segment costs (income)	6.9	1.8	0.6	9.3	(20.8)	(11.5)
Segment income (loss) - including NCI [1]	$ 1,521.9	$ 134.2	$ (77.0)	$ 1,579.1	$ (440.4)	$ 1,138.7
Additions to property, plant, equipment	$ 838.6	$ 208.5	$ (5.7)	$ 1,041.4	$ 21.9	$ 1,063.3
Total assets at year-end	6,930.6	2,125.6	217.4	9,273.6	1,035.4	10,309.0

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

Note S – Business Segments (Continued)

Geographic Information	Certain long-lived assets at December 31 [1]			
(Millions of dollars)	United States	Canada	Other	Total
2024	**$ 6,415.9**	**$ 1,389.5**	**$ 249.2**	**$ 8,054.6**
2023	6,555.0	1,497.3	172.8	8,225.1
2022	6,562.8	1,499.1	166.1	8,228.0

[1] Certain long-lived assets at December 31 represent total non-current assets, excluding investments, right-of-use operating lease assets, non-current receivables, deferred tax assets and other intangible assets.

Note T – Leases

Nature of Leases

The Company has entered into various operating and financial 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 natural gas field equipment.

Remaining lease terms range from 1 year to 16 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 Company discretion and mutual agreement between the Company and the 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**	**2024**	2023
Operating lease [1, 2]	Lease operating expenses	**$ 411,303**	$ 246,721
Operating lease [2]	Transportation, gathering and processing	**16,117**	37,797
Operating lease [2]	Selling and general expenses	**10,990**	9,859
Operating lease [2]	Other operating expense	**6,622**	675
Operating lease [2]	Exploration expenses	**38,974**	110,577
Operating lease [2]	Property, plant and equipment	**277,170**	204,595
Operating lease [2]	Asset retirement obligations	**10**	57,442
Finance lease			
Amortization of asset	Depreciation, depletion and amortization	**855**	1,505
Interest on lease liabilities	Interest expense, net	**193**	221
Sublease income	Other income	**(1,143)**	(1,402)
Net lease expense		**$ 761,091**	$ 667,990

[1] *Variable lease expenses.* For the years ended December 31, 2024 and 2023, includes variable lease expenses of $42.3 million and $36.7 million, respectively, 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, 2024, includes $236.4 million in lease operating expenses, $13.0 million for "Transportation, gathering and processing", $38.5 million for "Exploration expenses, including undeveloped lease amortization", $0.8 million in "Selling and general expenses", $6.2 million in "Other operating expense", $97.1 million in "Property, plant and equipment, net" and nil 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, 2023, includes $78.2 million in lease operating expenses, $29.4 million in "Transportation, gathering and processing", $80.3 million for "Exploration expenses, including undeveloped lease amortization", $1.6 million in "Selling and general expenses", $0.3 million in "Other operating expense", $112.7 million in "Property, plant and equipment, net" and $57.4 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.

Note T – Leases (Continued)

Maturity of Lease Liabilities

(Thousands of dollars)	Operating Leases	Finance Leases	Total
2025	$ 290,474	$ 1,257	$ 291,731
2026	123,487	1,257	124,744
2027	66,521	1,257	67,778
2028	59,398	1,257	60,655
2029	56,849	456	57,305
Remaining	406,450	927	407,377
Total future minimum lease payments	1,003,179	6,411	1,009,590
Less imputed interest	(212,590)	(1,534)	(214,124)
Present value of lease liabilities [1]	**$ 790,589**	**$ 4,877**	**$ 795,466**

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

Lease Term and Discount Rate

	December 31, 2024	December 31, 2023
Weighted average remaining lease term:		
Operating leases	**8 years**	10 years
Finance leases	**6 years**	5 years
Weighted average discount rate:		
Operating leases	**5.7 %**	5.9 %
Finance leases	**4.9 %**	4.7 %

Other Information

	Year Ended December 31,	
(Thousands of dollars)	**2024**	2023
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	**$ 328,847**	$ 271,488
Operating cash flows from finance leases	**311**	221
Financing cash flows from finance leases	**665**	622
Right-of-use assets obtained in exchange for lease liabilities:		
Operating leases [1]	**$ 349,312**	$ 5,923

[1] For the year ended December 31, 2024, right-of-use assets obtained in exchange for lease liabilities primarily includes $254.1 million related to the extension of an operating lease pertaining to a drill ship used in our U.S. Offshore business and $52.7 million pertaining to two drilling rigs and several natural gas compressor units at our U.S. Onshore business. December 31, 2023 includes $4.5 million related to natural gas compressor units at various U.S. Onshore locations.

Note U – Subsequent Event

On January 30, 2025, the Board of Directors of Murphy Oil Corporation (NYSE: MUR) declared a quarterly cash dividend on the Common Stock of Murphy Oil Corporation of $0.325 per share, or $1.30 per share on an annualized basis. The dividend is payable on March 3, 2025, to stockholders of record as of February 18, 2025.

The following unaudited schedules are presented in accordance with required disclosures about Oil and 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, natural gas and NGLs 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 judgments 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 2024 were $75.48 per BBL for NYMEX crude oil (WTI) and $2.13 per MCF for natural gas (Henry Hub). The average prices used for 2023 were $78.22 per BBL for NYMEX crude oil (WTI) and $2.64 per MCF for natural gas (Henry Hub). The average prices used for 2022 were $93.67 per BBL for NYMEX crude oil (WTI) and $6.36 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 (including hydrocarbon prices, operating costs, and development costs) 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 NGLs.

All crude oil, natural gas and NGL 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 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, 2024.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued
Schedule 1 – Summary of Total Proved Equivalent Reserves Based on Average Prices for 2021 – 2024

	Equivalents			
(Millions of barrels of oil equivalent)	Total	United States	Canada	Other
Proved developed and undeveloped reserves:				
December 31, 2021	716.9	343.4	372.8	0.7
Revisions of previous estimates	(23.6)	29.0	(52.8)	0.2
Improved recovery	5.3	5.3	—	—
Extensions and discoveries	80.1	20.6	59.5	—
Purchases of properties	5.0	5.0	—	—
Sale of properties	(4.4)	(4.4)	—	—
Production	(63.9)	(41.9)	(21.7)	(0.3)
December 31, 2022	715.4	357.0	357.8	0.6
Revisions of previous estimates	(13.3)	(13.3)	0.2	(0.2)
Improved recovery	0.4	—	0.4	—
Extensions and discoveries	112.6	12.7	87.3	12.6
Sale of properties	(5.2)	—	(5.2)	—
Production	(70.4)	(45.3)	(25.0)	(0.1)
December 31, 2023	739.5	311.1	415.5	12.9
Revisions of previous estimates	**14.3**	**8.1**	**6.3**	**(0.1)**
Improved recovery	**11.3**	**11.3**	**—**	**—**
Extensions and discoveries	**31.4**	**16.0**	**15.4**	**—**
Production	**(67.5)**	**(39.1)**	**(28.3)**	**(0.1)**
December 31, 2024 [1]	**729.0**	**307.4**	**408.9**	**12.7**
Proved developed reserves:				
December 31, 2021	419.2	241.9	176.8	0.6
December 31, 2022	436.0	264.2	171.3	0.5
December 31, 2023	425.5	223.2	202.0	0.3
December 31, 2024 [2]	**436.2**	**218.9**	**217.1**	**0.2**
Proved undeveloped reserves:				
December 31, 2021	297.7	101.6	196.0	0.1
December 31, 2022	279.4	92.8	186.5	0.1
December 31, 2023	314.0	87.9	213.5	12.6
December 31, 2024 [3]	**292.8**	**88.5**	**191.8**	**12.5**

[1] Total and United States includes proved reserves of 15.9 MMBOE, consisting of 14.5 MMBBL of oil, 0.6 MMBBL of NGLs and 5 BCF of natural gas attributable to the noncontrolling interest in MP GOM.

[2] Total and United States includes proved developed reserves of 14.4 MMBOE, consisting of 13.2 MMBBL of oil, 0.5 MMBBL of NGLs and 4.2 BCF of natural gas attributable to the noncontrolling interest in MP GOM.

[3] Total and United States includes proved undeveloped reserves of 1.5 MMBOE, consisting of 1.3 MMBBL of oil, 0.1 MMBBL of NGLs and 0.8 BCF of natural gas attributable to the noncontrolling interest in MP GOM.

[4] Totals within the tables may not add as a result of rounding.

Schedule 1 – Summary of Total Proved Equivalent Reserves Based on Average Prices for 2021 – 2024 (Continued)

2024 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The equivalent reserves revisions in 2024 resulted predominantly from performance adjustments in Tupper Montney and Eagle Ford Shale and positive revisions due to reduced royalty rates and delayed royalty incentive payouts resulting from lower commodity prices in Tupper Montney.

Improved Recovery – Proved equivalent reserves were added in 2024 for the non-operated St. Malo waterflood in the Gulf of America.

Extensions and discoveries - In 2024, proved equivalent reserves were added for drilling activities predominantly in Tupper Montney, the Eagle Ford Shale, and projects in the Gulf of America.

2023 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The equivalent reserves revisions in 2023 resulted predominantly from lower commodity prices in the U.S. and performance adjustments in Tupper Montney and the Eagle Ford Shale. These negative revisions were partially offset by positive revisions due to reduced royalty rates and delayed royalty incentive payouts resulting from lower commodity prices in Tupper Montney.

Extensions and discoveries - In 2023, proved equivalent reserves were added for drilling and expansion activities predominantly in Tupper Montney, the Eagle Ford Shale, and Vietnam.

Purchases and sales of properties - In 2023, the Company divested a portion of its working interest, in the Kaybob Duvernay and all of its non-operated Placid Montney assets.

2022 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The equivalent reserves revisions in 2022 resulted predominantly from increased royalty rates and accelerated royalty incentive payouts due to higher commodity prices in Tupper Montney. These negative revisions were partially offset by positive well performance in the Gulf of America.

Extensions and discoveries - In 2022, proved equivalent reserves were added for drilling and expansion activities predominantly in Tupper Montney and Kaybob Duvernay, as well as the Gulf of America and Eagle Ford Shale.

Purchases and sales of properties - In 2022, the Company acquired incremental working interests in two producing fields in the Gulf of America, and divested certain working interests in the Gulf of America and Eagle Ford Shale.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued
Schedule 2 – Summary of Proved Crude Oil Reserves Based on Average Prices for 2021 – 2024

(Millions of barrels)	Total	United States	Canada	Other
Proved developed and undeveloped crude oil reserves:				
December 31, 2021	291.5	255.0	35.9	0.6
Revisions of previous estimates	23.4	19.9	3.3	0.2
Improved recovery	4.7	4.7	—	—
Extensions and discoveries	18.9	16.1	2.8	—
Purchases of properties	4.2	4.2	—	—
Sale of properties	(3.6)	(3.6)	—	—
Production	(35.5)	(32.7)	(2.5)	(0.3)
December 31, 2022	303.6	263.6	39.5	0.5
Revisions of previous estimates	(10.8)	(8.9)	(1.8)	(0.1)
Improved recovery	0.4	—	0.4	—
Extensions and discoveries	22.5	8.9	1.5	12.1
Sale of properties	(2.0)	—	(2.0)	—
Production	(37.9)	(35.6)	(2.2)	(0.1)
December 31, 2023	275.8	228.0	35.4	12.4
Revisions of previous estimates	**6.6**	**6.6**	**0.1**	**(0.1)**
Improved recovery	**10.7**	**10.7**	**—**	**—**
Extensions and discoveries	**16.6**	**10.7**	**5.9**	**—**
Production	**(34.6)**	**(30.8)**	**(3.7)**	**(0.1)**
December 31, 2024 [1]	**275.1**	**225.2**	**37.7**	**12.2**
Proved developed crude oil reserves:				
December 31, 2021	191.5	174.9	16.0	0.5
December 31, 2022	209.0	194.4	14.2	0.4
December 31, 2023	186.3	163.7	22.3	0.3
December 31, 2024 [2]	**184.7**	**164.1**	**20.4**	**0.2**
Proved undeveloped crude oil reserves:				
December 31, 2021	99.9	80.0	19.8	0.1
December 31, 2022	94.6	69.2	25.3	0.1
December 31, 2023	89.5	64.3	13.1	12.1
December 31, 2024 [3]	**90.4**	**61.1**	**17.3**	**12.0**

[1] Total and United States includes proved reserves of 14.5 MMBBL attributable to the noncontrolling interest in MP GOM.

[2] Total and United States includes proved developed reserves of 13.2 MMBBL attributable to the noncontrolling interest in MP GOM.

[3] Total and United States includes proved undeveloped reserves of 1.3 MMBBL attributable to the noncontrolling interest in MP GOM.

[4] Totals within the tables may not add as a result of rounding.

2024 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates - The crude oil reserves revisions in 2024 resulted predominantly from performance adjustments in the Eagle Ford Shale and Gulf of America.

Improved Recovery – Proved oil reserves were added in 2024 for the non-operated St. Malo waterflood in the Gulf of America.

Extensions and discoveries - In 2024, proved oil reserves were added for drilling activities predominantly in the Eagle Ford Shale and Gulf of America.

2023 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates - The negative crude oil reserves revisions in 2023 resulted predominantly from impacts of lower commodity prices in the U.S. and performance adjustments in the Eagle Ford Shale and the Gulf of America.

Extensions and discoveries - In 2023, proved oil reserves were added for drilling and expansion activities predominantly in the Eagle Ford Shale and Vietnam.

Purchases and sales of properties - In 2023, the Company divested a portion of its working interest in the Kaybob Duvernay and all of its non-operated Placid Montney assets.

2022 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates - The positive crude oil reserves revisions in 2022 resulted predominantly from improved well performance in the Gulf of America and impacts of higher commodity prices in the U.S.

Extensions and discoveries - In 2022, proved oil reserves were added for drilling and expansion activities predominantly in the Gulf of America and the Eagle Ford Shale.

Purchases and sales of properties - In 2022, the Company acquired incremental working interests in two producing fields in the Gulf of America, and divested certain working interests in the Gulf of America and Eagle Ford Shale.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued
Schedule 3 – Summary of Proved Natural Gas Liquids Reserves Based on Average Prices for 2021 – 2024

(Millions of barrels)	Total	United States	Canada	Other
Proved developed and undeveloped NGL reserves:				
December 31, 2021	38.4	35.1	3.3	—
Revisions of previous estimates	4.4	3.9	0.5	—
Improved recovery	0.2	0.2	—	—
Extensions and discoveries	2.5	1.9	0.6	—
Purchase of properties	0.3	0.3	—	—
Sale of properties	(0.2)	(0.2)	—	—
Production	(3.9)	(3.6)	(0.3)	—
December 31, 2022	41.7	37.6	4.1	—
Revisions of previous estimates	(1.4)	(1.2)	(0.2)	—
Extensions and discoveries	2.0	1.7	0.3	—
Sale of properties	(0.6)	—	(0.6)	—
Production	(4.1)	(3.8)	(0.3)	—
December 31, 2023	37.6	34.3	3.3	—
Revisions of previous estimates	**1.2**	**0.3**	**0.9**	**—**
Improved recovery	**0.4**	**0.4**	**—**	**—**
Extensions and discoveries	**2.9**	**2.4**	**0.5**	**—**
Production	**(3.5)**	**(3.3)**	**(0.2)**	**—**
December 31, 2024 [1]	**38.6**	**34.1**	**4.5**	**—**
Proved developed NGL reserves:				
December 31, 2021	28.4	25.6	2.8	—
December 31, 2022	29.7	27.4	2.3	—
December 31, 2023	25.9	24.1	1.8	—
December 31, 2024 [2]	**24.1**	**21.9**	**2.2**	**—**
Proved undeveloped NGL reserves:				
December 31, 2021	10.0	9.5	0.5	—
December 31, 2022	12.0	10.2	1.8	—
December 31, 2023	11.7	10.2	1.5	—
December 31, 2024 [3]	**14.5**	**12.2**	**2.3**	**—**

[1] Total and United States includes total proved reserves of 0.6 MMBBL attributable to the noncontrolling interest in MP GOM.
[2] Total and United States includes proved developed reserves of 0.5 MMBBL attributable to the noncontrolling interest in MP GOM.
[3] Total and United States includes proved undeveloped reserves of 0.1 MMBBL attributable to the noncontrolling interest in MP GOM.

Schedule 3 – Summary of Proved Natural Gas Liquids Reserves Based on Average Prices for 2021 – 2024 (Continued)

2024 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates - The NGL reserves revisions in 2024 resulted predominantly from performance adjustments in Tupper Montney and Eagle Ford Shale, and positive revisions due to reduced royalty rates and delayed royalty incentive payouts resulting from lower commodity prices in Tupper Montney.

Improved Recovery – Proved NGL reserves were added in 2024 for the non-operated St. Malo waterflood in the Gulf of America.

Extensions and discoveries - In 2024, proved NGL reserves were added for drilling activities predominantly in Tupper Montney and Eagle Ford Shale.

2023 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates - The negative NGL reserves revisions in 2023 resulted predominantly from impacts of lower commodity prices in the U.S. and performance adjustments in the Eagle Ford Shale. These revisions were partially offset by improvements in the Gulf of America.

Extensions and discoveries - In 2023, proved NGL reserves were added for drilling and expansion activities predominantly in the Eagle Ford Shale.

Purchases and sales of properties - In 2023, the Company divested a portion of its working interest in the Kaybob Duvernay and all of its non-operated Placid Montney assets.

2022 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates - The positive NGL reserves revisions in 2022 resulted predominantly from improved well performance in the Gulf of America, Eagle Ford Shale, and Kaybob Duvernay.

Extensions and discoveries - In 2022, proved NGL reserves were added for drilling and expansion activities predominantly in the Gulf of America and Eagle Ford Shale, as well as in Tupper Montney and Kaybob Duvernay.

Purchases and sales of properties - In 2022, the Company acquired incremental working interests in two producing fields in the Gulf of America, and divested certain working interests in the Gulf of America and Eagle Ford Shale.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued
Schedule 4 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2021 – 2024

(Billions of cubic feet)	Total	United States	Canada	Other
Proved developed and undeveloped natural gas reserves:				
December 31, 2021	2,322.3	320.3	2,001.8	0.2
Revisions of previous estimates	(309.8)	30.7	(340.5)	—
Improved recovery	2.6	2.6	—	—
Extensions and discoveries	352.4	15.7	336.7	—
Purchases of properties	2.9	2.9	—	—
Sale of properties	(3.6)	(3.6)	—	—
Production	(146.9)	(33.7)	(113.2)	—
December 31, 2022	2,219.9	334.9	1,884.8	0.2
Revisions of previous estimates	(6.9)	(19.0)	12.1	—
Extensions and discoveries	528.9	12.3	513.8	2.8
Sale of properties	(15.6)	—	(15.6)	—
Production	(170.1)	(35.1)	(135.0)	—
December 31, 2023	2,556.2	293.1	2,260.1	3.0
Revisions of previous estimates	**39.1**	**7.7**	**31.4**	**—**
Improved recovery	**1.2**	**1.2**	**—**	**—**
Extensions and discoveries	**71.4**	**17.0**	**54.4**	**—**
Production	**(176.1)**	**(30.1)**	**(146.0)**	**—**
December 31, 2024 [1,4]	**2,491.8**	**288.9**	**2,199.9**	**3.0**
Proved developed natural gas reserves:				
December 31, 2021	1,196.0	248.1	947.7	0.2
December 31, 2022	1,183.1	254.1	928.8	0.2
December 31, 2023	1,279.3	212.4	1,066.7	0.2
December 31, 2024 [2,4]	**1,364.2**	**196.8**	**1,167.2**	**0.2**
Proved undeveloped natural gas reserves:				
December 31, 2021	1,126.4	72.2	1,054.1	—
December 31, 2022	1,036.8	80.8	956.0	—
December 31, 2023	1,276.9	80.7	1,193.4	2.8
December 31, 2024 [3]	**1,127.6**	**92.1**	**1,032.7**	**2.8**

[1] Total and United States includes total proved reserves of 5.0 BCF attributable to the noncontrolling interest in MP GOM.

[2] Total and United States includes proved developed reserves of 4.2 BCF attributable to the noncontrolling interest in MP GOM.

[3] Total and United States includes proved undeveloped reserves of 0.8 BCF attributable to the noncontrolling interest in MP GOM.

[4] Includes proved natural gas reserves to be consumed in operations as fuel of 67.9 BCF, 36.0 BCF and 2.8 BCF for the U.S., Canada and Other, respectively, with 1.1 BCF attributable to the noncontrolling interest in MP GOM.

[5] Totals within the tables may not add as a result of rounding.

Schedule 4 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2021 – 2024 (Continued)

2024 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates - The natural gas reserves revisions in 2024 resulted predominantly from performance adjustments in Tupper Montney and Eagle Ford Shale, and positive revisions due to reduced royalty rates and delayed royalty incentive payouts resulting from lower commodity prices in Tupper Montney.

Improved Recovery – Proved natural gas reserves were added in 2024 for the non-operated St. Malo waterflood in the Gulf of America.

Extensions and discoveries - In 2024, proved natural gas reserves were added for drilling activities predominantly in Tupper Montney and Eagle Ford Shale.

2023 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates - The negative natural gas reserves revisions in 2023 resulted predominantly from lower commodity prices in the U.S. and performance adjustments in Tupper Montney and Eagle Ford Shale. These negative revisions were partially offset by positive revisions in the Gulf of America, as well as reduced royalty rates and delayed royalty incentive payouts resulting from lower commodity prices in Tupper Montney.

Extensions and discoveries - In 2023, proved natural gas reserves were added for drilling and expansion activities predominantly in Tupper Montney.

Purchases and sales of properties - In 2023, the Company divested a portion of its working interest in the Kaybob Duvernay and all of its non-operated Placid Montney assets.

2022 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates - The negative natural gas reserves revisions in 2022 resulted predominantly from increased royalty rates and accelerated royalty incentive payouts due to higher commodity prices in Tupper Montney.

Extensions and discoveries - In 2022, proved natural gas reserves were added for drilling and expansion activities predominantly in Tupper Montney, as well as in the Gulf of America and Eagle Ford Shale.

Purchases and sales of properties - In 2022, the Company acquired incremental working interests in two producing fields in the Gulf of America and divested certain working interests in the Gulf of America and Eagle Ford Shale.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued
Schedule 5 – Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

(Millions of dollars)	United States	Canada	Other	Total
Year ended December 31, 2024				
Property acquisition costs				
Unproved	**$ 7.8**	**$ 0.2**	**$ —**	**$ 8.0**
Proved	**—**	**—**	**—**	**—**
Total acquisition costs	**7.8**	**0.2**	**—**	**8.0**
Exploration costs	**85.3**	**0.4**	**60.2**	**145.9**
Development costs	**598.7**	**137.7**	**45.1**	**781.5**
Total costs incurred	**691.8**	**138.3**	**105.3**	**935.4**
Charged to expense				
Dry hole expense	**70.9**	**—**	**2.3**	**73.2**
Geophysical and other costs	**19.2**	**0.4**	**31.2**	**50.8**
Total charged to expense	**90.1**	**0.4**	**33.5**	**124.0**
Property additions	**$ 601.7**	**$ 137.9**	**$ 71.8**	**$ 811.4**
Year ended December 31, 2023				
Property acquisition costs				
Unproved	$ —	$ —	$ 8.5	$ 8.5
Proved	12.8	—	14.3	27.1
Total acquisition costs	12.8	—	22.8	35.6
Exploration costs	157.8	0.4	39.9	198.1
Development costs	667.2	206.2	7.4	880.8
Total costs incurred	837.8	206.6	70.1	1,114.5
Charged to expense				
Dry hole expense	153.1	—	16.7	169.8
Geophysical and other costs	13.4	0.4	40.3	54.1
Total charged to expense	166.5	0.4	57.0	223.9
Property additions	$ 671.3	$ 206.2	$ 13.1	$ 890.6
Year ended December 31, 2022				
Property acquisition costs				
Unproved	$ 1.8	$ —	$ —	$ 1.8
Proved	128.5	—	—	128.5
Total acquisition costs	130.3	—	—	130.3
Exploration costs	42.2	0.8	70.3	113.3
Development costs	704.9	208.5	4.3	917.7
Total costs incurred	877.4	209.3	74.6	1,161.3
Charged to expense				
Dry hole expense	23.0	—	59.1	82.1
Geophysical and other costs	15.8	0.8	21.1	37.7
Total charged to expense	38.8	0.8	80.2	119.8
Property additions	$ 838.6	$ 208.5	$ (5.6)	$ 1,041.5

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued
Schedule 6 – Results of Operations for Oil and Gas Producing Activities [1]

(*Millions of dollars*)	United States	Canada	Other	Total
Year ended December 31, 2024				
Revenues				
Crude oil and natural gas liquids sales	**$ 2,436.0**	**$ 272.3**	**$ 6.6**	**$ 2,714.9**
Natural gas sales	**67.8**	**232.2**	**—**	**300.0**
Sales of purchased natural gas	**—**	**3.7**	**—**	**3.7**
Total oil and natural gas revenues	**2,503.8**	**508.2**	**6.6**	**3,018.6**
Other operating revenues	**4.5**	**1.5**		**6.0**
Total revenues	**2,508.3**	**509.7**	**6.6**	**3,024.5**
Costs and expenses				
Lease operating expenses	**749.9**	**185.5**	**1.6**	**937.0**
Severance and ad valorem taxes	**37.8**	**1.4**	**—**	**39.2**
Transportation, gathering and processing	**130.9**	**79.9**	**—**	**210.8**
Costs of purchased natural gas	**—**	**3.1**	**—**	**3.1**
Exploration costs charged to expense	**90.0**	**0.4**	**33.5**	**123.9**
Undeveloped lease amortization	**6.2**	**0.1**	**3.3**	**9.6**
Depreciation, depletion and amortization	**709.2**	**146.0**	**1.7**	**856.9**
Accretion of asset retirement obligations	**43.1**	**8.6**	**0.7**	**52.4**
Impairment of assets	**62.9**	**—**	**—**	**62.9**
Selling and general expenses	**(3.3)**	**20.4**	**6.7**	**23.8**
Other expenses (benefits)	**(5.6)**	**3.3**	**2.6**	**0.3**
Total costs and expenses	**1,821.1**	**448.7**	**50.1**	**2,319.9**
Results of operations before taxes	**687.2**	**61.0**	**(43.5)**	**704.6**
Income tax expense (benefit)	**125.3**	**12.0**	**(31.0)**	**106.3**
Results of operations	**$ 561.9**	**$ 49.0**	**$ (12.5)**	**$ 598.4**
Year ended December 31, 2023				
Revenues				
Crude oil and natural gas liquids sales	$ 2,829.1	$ 165.7	$ 11.0	$ 3,005.8
Natural gas sales	92.7	278.2	—	370.9
Sales of purchased natural gas	—	72.2	—	72.2
Total oil and natural gas revenues	2,921.8	516.1	11.0	3,448.9
Other operating revenues	6.5	1.4	—	7.9
Total revenues	2,928.3	517.5	11.0	3,456.8
Costs and expenses				
Lease operating expenses	630.7	151.8	1.9	784.4
Severance and ad valorem taxes	41.4	1.4	—	42.8
Transportation, gathering and processing	157.0	76.0	—	233.0
Costs of purchased natural gas	—	51.7	—	51.7
Exploration costs charged to expense	166.5	0.4	57.0	223.9
Undeveloped lease amortization	8.1	0.1	2.7	10.9
Depreciation, depletion and amortization	706.0	142.2	2.3	850.5
Accretion of asset retirement obligations	37.8	7.8	0.4	46.0
Selling and general expenses	11.8	16.5	9.4	37.7
Other expenses	31.2	16.8	8.9	56.9
Total costs and expenses	1,790.5	464.7	82.6	2,337.8
Results of operations before taxes	1,137.8	52.8	(71.6)	1,119.0
Income tax expense (benefit)	232.7	11.2	(6.1)	237.8
Results of operations	$ 905.1	$ 41.6	$ (65.5)	$ 881.2

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND 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, 2022				
Revenues				
Crude oil and natural gas liquids sales	$ 3,210.3	$ 267.5	$ 22.8	$ 3,500.6
Natural gas sales	225.3	312.6	—	537.9
Sales of purchased natural gas	0.2	181.5	—	181.7
Total oil and natural gas revenues	3,435.8	761.6	22.8	4,220.2
Other operating revenues	25.4	1.3	—	26.7
Total revenues	3,461.2	762.9	22.8	4,246.9
Costs and expenses				
Lease operating expenses	522.7	155.1	1.5	679.3
Severance and ad valorem taxes	55.7	1.3	—	57.0
Transportation, gathering and processing	142.2	70.5	—	212.7
Costs of purchased natural gas	0.2	171.8	—	172.0
Exploration costs charged to expense	38.8	0.8	80.2	119.8
Undeveloped lease amortization	8.7	0.2	4.4	13.3
Depreciation, depletion and amortization	617.0	141.5	5.4	763.9
Accretion of asset retirement obligations	36.5	9.6	0.1	46.2
Selling and general expenses	20.4	21.9	2.2	44.5
Other expenses	126.3	12.4	3.1	141.8
Total costs and expenses	1,568.5	585.1	96.9	2,250.5
Results of operations before taxes	1,892.7	177.8	(74.1)	1,996.4
Income tax expense (benefit)	370.8	43.6	2.9	417.3
Results of operations	$ 1,521.9	$ 134.2	$ (77.0)	$ 1,579.1

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued
Schedule 7 – Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves [1]

(*Millions of dollars*)	United States	Canada	Other	Total
December 31, 2024				
Future cash inflows	**$ 18,118.1**	**$ 6,304.4**	**$ 1,012.9**	**$ 25,435.4**
Future development costs	**(2,024.9)**	**(825.9)**	**(252.5)**	**(3,103.3)**
Future production costs	**(7,645.7)**	**(4,026.5)**	**(341.7)**	**(12,013.9)**
Future income taxes	**(893.5)**	**(251.2)**	**(203.4)**	**(1,348.1)**
Future net cash flows	**7,554.0**	**1,200.8**	**215.3**	**8,970.1**
10% annual discount for estimated timing of cash flows	**(2,887.3)**	**(486.0)**	**(200.9)**	**(3,574.2)**
Standardized measure of discounted future net cash flows	**$ 4,666.7**	**$ 714.8**	**$ 14.4**	**$ 5,395.9**
December 31, 2023				
Future cash inflows	$ 18,927.6	$ 8,012.7	$ 1,004.2	$ 27,944.5
Future development costs	(1,685.3)	(769.6)	(304.3)	(2,759.2)
Future production costs	(7,856.2)	(4,223.6)	(288.7)	(12,368.5)
Future income taxes	(1,057.5)	(634.6)	(121.3)	(1,813.4)
Future net cash flows	8,328.6	2,384.9	289.9	11,003.4
10% annual discount for estimated timing of cash flows	(2,840.6)	(1,056.9)	(252.5)	(4,150.0)
Standardized measure of discounted future net cash flows	$ 5,488.0	$ 1,328.0	$ 37.4	$ 6,853.4
December 31, 2022				
Future cash inflows	$ 27,277.9	$ 12,360.2	$ 59.2	$ 39,697.3
Future development costs	(1,594.5)	(642.4)	(1.4)	(2,238.3)
Future production costs	(8,297.4)	(4,199.0)	(12.1)	(12,508.5)
Future income taxes	(2,606.8)	(1,788.7)	(5.4)	(4,400.9)
Future net cash flows	14,779.2	5,730.1	40.3	20,549.6
10% annual discount for estimated timing of cash flows	(5,709.8)	(3,015.6)	(11.0)	(8,736.4)
Standardized measure of discounted future net cash flows	$ 9,069.4	$ 2,714.5	$ 29.3	$ 11,813.2

[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 AND GAS INFORMATION (UNAUDITED) – Continued
Schedule 7 – Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves [1] (Continued)

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

(Millions of dollars)	**2024**	2023	2022
Net changes in prices and production costs [2]	**$ (1,116.5)**	$ (5,845.6)	$ 4,812.2
Net changes in development costs	**(152.7)**	(78.8)	(531.1)
Sales and transfers of oil and natural gas produced, net of production costs	**(1,824.8)**	(2,264.8)	(2,917.4)
Net change due to extensions and discoveries	**583.7**	770.4	1,223.5
Net change due to purchases and sales of proved reserves	**—**	(96.1)	102.1
Development costs incurred	**668.6**	703.7	769.3
Accretion of discount	**773.5**	1,393.3	802.6
Revisions of previous quantity estimates	**(688.1)**	(771.5)	1,652.9
Net change in income taxes	**298.8**	1,229.6	(1,399.9)
Net (decrease) increase	**(1,457.5)**	(4,959.8)	4,514.2
Standardized measure at January 1	**6,853.4**	11,813.2	7,299.0
Standardized measure at December 31	**$ 5,395.9**	$ 6,853.4	$ 11,813.2

[1] Includes noncontrolling interest in MP GOM.

[2] The average prices used for 2024 were $75.48 per BBL for NYMEX crude oil (WTI) and $2.13 per MCF for natural gas (Henry Hub). The average prices used for 2023 were $78.22 per BBL for NYMEX crude oil (WTI) and $2.64 per MCF for natural gas (Henry Hub). The average prices used for 2022 were $93.67 per BBL for NYMEX crude oil (WTI) and $6.36 per MCF for natural gas (Henry Hub).

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued
Schedule 8 – Capitalized Costs Relating to Oil and Gas Producing Activities

(*Millions of dollars*)	United States	Canada	Other	Total
December 31, 2024				
Unproved oil and natural gas properties [1]	**$ 247.3**	**$ 6.6**	**$ 29.1**	**$ 283.0**
Proved oil and natural gas properties	**16,598.8**	**4,498.1**	**246.7**	**21,343.6**
Gross capitalized costs	**16,846.1**	**4,504.7**	**275.8**	**21,626.6**
Accumulated depreciation, depletion and amortization				
Unproved oil and natural gas properties	**(111.0)**	**—**	**(20.7)**	**(131.7)**
Proved oil and natural gas properties	**(10,326.2)**	**(3,116.2)**	**(44.2)**	**(13,486.6)**
Net capitalized costs	**$ 6,408.9**	**$ 1,388.5**	**$ 210.9**	**$ 8,008.3**
December 31, 2023				
Unproved oil and natural gas properties [1]	$ 337.3	$ 13.1	$ 49.7	$ 400.1
Proved oil and natural gas properties	15,868.4	4,716.0	153.7	20,738.1
Gross capitalized costs	16,205.7	4,729.1	203.4	21,138.2
Accumulated depreciation, depletion and amortization				
Unproved oil and natural gas properties	(105.3)	—	(17.4)	(122.7)
Proved oil and natural gas properties	(9,552.9)	(3,233.7)	(42.8)	(12,829.4)
Net capitalized costs	$ 6,547.5	$ 1,495.4	$ 143.2	$ 8,186.1

[1] 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]
Year ended December 31, 2024					
Revenue from contracts with customers	**$ 794.8**	**$ 801.0**	**$ 753.2**	**$ 669.6**	**$ 3,018.6**
Income from continuing operations before income taxes	**145.6**	**189.6**	**153.8**	**78.6**	**567.6**
Income from continuing operations	**115.5**	**156.9**	**151.7**	**65.2**	**489.3**
Net income including noncontrolling interest	**114.7**	**156.3**	**151.1**	**64.4**	**486.5**
Net income attributable to Murphy	**90.0**	**127.7**	**139.1**	**50.3**	**407.1**
Income from continuing operations per common share [2]					
Basic	**0.60**	**0.84**	**0.93**	**0.35**	**2.73**
Diluted	**0.60**	**0.83**	**0.93**	**0.34**	**2.72**
Net income per common share [2]					
Basic	**0.59**	**0.84**	**0.93**	**0.35**	**2.71**
Diluted	**0.59**	**0.83**	**0.93**	**0.34**	**2.70**
Cash dividend per common share	**0.300**	**0.300**	**0.300**	**0.300**	**1.200**
Year ended December 31, 2023					
Revenue from contracts with customers	$ 840.0	$ 812.9	$ 953.8	$ 842.2	$ 3,448.9
Income from continuing operations before income taxes	267.9	127.3	356.3	169.5	921.0
Income from continuing operations	214.0	92.5	278.2	140.5	725.2
Net income including noncontrolling interest	214.3	91.9	277.8	139.7	723.7
Net income attributable to Murphy	191.6	98.3	255.3	116.4	661.6
Income from continuing operations per common share [2]					
Basic	1.23	0.63	1.64	0.76	4.27
Diluted	1.22	0.62	1.63	0.75	4.23
Net income per common share [2]					
Basic	1.23	0.63	1.64	0.76	4.26
Diluted	1.22	0.62	1.63	0.75	4.22
Cash dividend per common share	0.275	0.275	0.275	0.275	1.100

[1] Revenue from contracts with customers, "Income from continuing operations before income taxes", "Income from continuing operations" and "Net income including noncontrolling interest" include results attributable to the noncontrolling interest in MP GOM.

[2] The sum of quarterly income (loss) from continuing operations per share and 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	Balance at December 31
2024					
Deducted from asset accounts:					
Allowance for doubtful accounts	**$ 1.6**	**$ —**	**$ —**	**$ —**	**$ 1.6**
Deferred tax asset valuation allowance	**146.9**	**2.6**	**—**	**—**	**149.5**
2023					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 1.6	$ —	$ —	$ —	$ 1.6
Deferred tax asset valuation allowance	136.0	10.9	—	—	146.9
2022					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 1.6	$ —	$ —	$ —	$ 1.6
Deferred tax asset valuation allowance	111.2	24.8	—	—	136.0

DEFINITIONS

Currencies:

CAD or C$ - Canadian dollar
USD or US$ - United States dollar

Units of Measurement:

BBL - Barrels
BCF - Billion cubic feet
BOE - Barrels of oil equivalent
BOEPD - Barrels of oil equivalent per day
MCF - Thousand cubic feet
MMBBL - Million barrels of oil
MMBOE - Million barrels of oil equivalent
MMBTU - Million British thermal units
MMCF - Million cubic feet

Industry:

AECO - Alberta Energy Company and is the Canadian benchmark price for natural gas
Crude oil - Collectively, crude oil and condensate hydrocarbons

Development well - A well that is drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive
Dry hole - An exploratory well that does not find oil or natural gas in commercial quantities
E&P - Exploration and production
Exploratory well - A 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
Hydrocarbons - Organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products
Liquids - Collectively, crude oil, condensate and natural gas liquid hydrocarbons
Net acres or net wells - The portions of gross acres or gross wells owned by the Company
NGLs - Natural gas liquids
NYMEX - New York Mercantile Exchange
OPEC - Organization of the Petroleum Exporting Countries
Operator - The company serving as the manager and often the decision-maker of a drilling or production project
Production Sharing Contract (PSC) - Agreement between extracting company(ies) and a host country regarding each party's share of production after stipulated exploratory and development costs are recovered
QRE - Qualified reserve estimator
Seismic - Two-dimensional or three-dimensional images created by bouncing sound waves off underground rock formations that are used to determine the best places to drill for hydrocarbons
Working interest - Right to drill and produce oil and natural gas on the leased acreage, as well as the obligation to pay costs
WTI - West Texas Intermediate

Accounting:

ARO - Asset retirement obligation
ASC - Accounting Standards Codification
ASU - Accounting Standards Update

DEFINITIONS - Continued

CODM - Chief Operating Decision Maker
DD&A - Depreciation, depletion and amortization
EBITDA - Earnings before interest, taxes, depreciation and amortization
FASB - Financial Accounting Standards Board
GAAP - U.S. Generally Accepted Accounting Principles
NCI - Noncontrolling interest
PCAOB - Public Company Accounting Oversight Board
SEC - U.S. Securities and Exchange Commission

Other:

AIP - Annual Incentive Plan
BOEM - U.S. Bureau of Ocean Energy Management
BSEE - U.S. Bureau of Safety and Environmental Enforcement
CRSU - Cash-settled restricted time-based stock unit
EPA - U.S. Environmental Protection Agency
ESG - Environmental, Social and Governance
GHG - Greenhouse gas
IRA - Inflation Reduction Act
MP GOM - MP Gulf of Mexico, LLC
PAI - Petrobras America Inc.
PSU - Performance-based restricted stock unit
RCF - Revolving credit facility
ROACE - Return on average capital employed
RSU - Time-based restricted stock unit
SAR - Stock appreciation right
SOFR - Secured Overnight Financing Rate
TCFD - Task Force on Climate-related Financial Disclosures
TSR - Total Shareholder Return
WEC - Waste Emission Charge

SEVERANCE PROTECTION AGREEMENT

THIS AGREEMENT (the "**Agreement**") made as of the [•] day of [•], [•] (the "Effective Date"), by and between Murphy Oil Corporation, a Delaware corporation, and its Successors and Assigns (collectively, the "**Company**") and [•] ("**Executive**"). Unless otherwise indicated, capitalized terms used in this Agreement shall have the meanings as set forth in Section 15.

WHEREAS, the Board of Directors of the Company, acting through its Compensation Committee (the "**Committee**"), recognizes that the possibility of a Change in Control exists and that the threat or the occurrence of a Change in Control and its inherent uncertainties can result in significant distractions of its key management personnel;

WHEREAS, the Committee has determined that it is essential and in the best interest of the Company and its stockholders to retain the services of Executive in the event of a threat or occurrence of a Change in Control and to ensure Executive's continued dedication and efforts in such event; and

WHEREAS, in order to induce Executive to remain in the employ of the Company, particularly in the event of a threat or occurrence of a Change in Control, the Company desires to enter into this Agreement with Executive to provide Executive with certain benefits in the event Executive's employment is terminated as a result of, or in connection with, a Change in Control.

NOW, THEREFORE, in consideration of the respective agreements of the parties contained herein, it is agreed as follows:

1. Term of Agreement; Consent. The term of this Agreement (the "**Term**") shall commence as of the Effective Date and shall continue in effect until the third anniversary of the Effective Date; provided, however, that the Term shall automatically be extended for additional successive one year periods unless either the Company or Executive provides written notice to the other at least 90 days prior to the end of the Term as then in effect that the Term shall not be so extended. Notwithstanding the foregoing, (i) if a Change in Control occurs during the Term, the Term shall remain in effect until the date that is 24 months after the occurrence of a Change in Control and (ii) this Agreement shall expire and be of no further force and effect in the event of any termination of Executive's employment that occurs prior to a Change in Control.

2. Termination of Employment.

2.1 Amount of Compensation and Benefits. If, during the Term, Executive's employment with the Company is terminated within 24 months following a Change in Control, Executive shall be entitled to the following compensation and benefits:

(a) If such termination of Executive's employment is (1) by the Company for Cause or Disability, (2) by reason of Executive's death, or (3) by Executive for other than Good Reason, the Company shall pay Executive the Accrued Compensation.

(b) If such termination of Executive's employment is for any reason other than as specified in Section 2.1(a), Executive shall be entitled to the following payments and benefits:

(i) the Company shall pay Executive the Accrued Compensation;

(ii) the Company shall pay Executive as severance pay an amount in cash equal to [three (3)][two and a half (2.5)][1] times the sum of (A) the Base Salary and (B) the Bonus Amount, paid in a single lump sum cash payment on the 60th day after the date of the termination of the Executive's employment; and

(iii) Any stock options or other equity-based awards including, without limitation, restricted stock unit awards and stock appreciation rights held by Executive that are outstanding on the Termination Date (collectively, "**Company Equity Awards**") and any stock options or other equity-based awards into which the Company Equity Awards are converted, or stock options or other equity-based awards granted in substitution for the Company Equity Awards, shall on the Termination Date become fully vested, exercisable and payable, as applicable; *provided*, *however*, that all performance based restricted stock unit or similar awards shall be paid out at target or 100% performance, as the case may be. Notwithstanding the foregoing, no stock option or other equity-based award shall be exercisable after the specified maximum term of the stock option or other equity-based award, as set forth in the applicable Company equity- based compensation plan or award agreement.

(iv) For the [36][30][2]-month period immediately following the Termination Date, the Company shall arrange to provide Executive and Executive's dependents life, accident, and health insurance benefits substantially similar to those provided to Executive and Executive's dependents immediately prior to the Termination Date or, if more favorable to Executive, those provided to Executive and Executive's dependents immediately prior to

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[1] Insert as applicable.

[2] Insert as applicable.

the first occurrence of an event or circumstance constituting Good Reason, at no greater cost to Executive than the cost to Executive immediately prior to such date or occurrence; *provided*, *however*, if providing such benefits could subject the Company, Executive or any applicable Company plan to any excise tax for failure to comply with any law applicable to group health plans which becomes effective after the Effective Date, the Company and Executive shall in good faith renegotiate this Section 2.1(b)(iv) to achieve a result that preserves as closely as possible the parties' intended after-tax economic positions under this Section 2.1(b)(iv).

(c) If at the time of Executive's Separation from Service, Executive is a Specified Employee, any and all amounts payable under this Section 2 in connection with such Separation from Service that constitute deferred compensation subject to Section 409A of the Code ("**Section 409A**"), as determined by the Company in its sole discretion, and that would (but for this sentence) be payable within six (6) months following such Separation from Service, shall instead be paid on the date that follows the date of such Separation from Service by six months. For purposes of the preceding sentence, "**Separation from Service**" shall be determined in a manner consistent with subsection (a)(2)(A)(i) of Section 409A and the term "**Specified Employee**" shall mean an individual determined by the Company to be a Specified Employee as defined in subsection (a)(2)(B)(i) of Section 409A. In the event of any delay in payments under this Section 2.1(c), the deferred amount shall bear interest at the 10-year Treasury rate in effect on the Termination Date until paid.

(d) The amounts provided for in Sections (b)(ii), (b)(iii) and 2.1(b)(iv) (the "**Severance Amounts**") shall be subject to Executive's execution and delivery of a timely (but in no event later than 55 days after the date of the termination of Executive's employment with the Company) and effective release of claims, in a mutually agreeable form (the "**Release of Claims**"), provided that if the aforementioned 55-day period begins in one taxable year and ends in the following taxable year, payment of the Severance Amounts shall not commence or occur until the following taxable year. Any such Release of Claims shall preserve all of Executive's (i) vested rights, if any and to the extent applicable, under (x) the Company's equity-based compensation plans or award agreements and (y) the Company's other employee benefit plans and (ii) rights, to the extent applicable, under the Company's director and officer indemnification arrangements. If Executive refuses to execute and deliver the Release of Claims, or if Executive revokes the Release of Claims as provided therein, Executive shall not receive the Severance Amounts or any other payment or benefit to which Executive is not otherwise entitled.

(e) Executive shall not be required to mitigate the amount of any payment provided for in this Agreement by seeking other employment or otherwise and no such payment shall be offset or reduced by the amount of any compensation or benefits provided to Executive in any subsequent employment.

(f) (i) In order to ensure that, following a Change in Control, sufficient assets are available to satisfy the Company's obligations to Executive and Executive's beneficiaries under the SERP, the Company may establish a grantor or "Rabbi" trust with an independent reputable financial institution as trustee, to which the Company may, in its discretion, contribute cash or other property to provide for the payment of benefits to Executive and Executive's beneficiaries under the SERP (the "**Trust**"). The Trust shall comply in all material respects with the model grantor trust set forth in Rev. Proc. 92-64, 1992-2C.B422.

(ii) Notwithstanding the foregoing, no later than 60 days prior to a Change in Control, the Company shall (x) establish a Trust if one has not been previously established and (y) transfer to the Trust such assets as the Company determines in good faith are at least equal to, on a present value basis, the Company's liabilities to Executive and Executive's beneficiaries under the SERP (the "**SERP Liabilities**") determined as of the date 24 months after the date of the Change in Control. The Company shall, from time to time therefore make additional contributions to the Trust such that the assets therein are at all times at least equal to the then SERP Liabilities.

(iii) The provisions of the SERP shall determine the rights of Executive and Executive's beneficiaries to receive distributions from the Trust in respect of benefits otherwise payable to Executive or Executive's beneficiaries under the SERP, and any such distribution shall reduce the Company's obligations under the SERP. The provisions of the Trust shall govern the rights of the Company, Executive and the creditors of the Company to the assets transferred to the Trust. On and after a Change in Control, the Trust may not be (x) amended in any way adverse to Executive or Executive's beneficiaries, and (y) terminated or revoked unless and until all SERP Liabilities have been paid or otherwise distributed to Executive and Executive's beneficiaries, as applicable.

(g) Notwithstanding the foregoing, the payments otherwise due hereunder may be limited to the extent provided in Section 4 hereof.

2.2 Coordination with other Compensation and Benefits.

(a) The severance pay and benefits provided for in this Section 2 following a Change in Control shall be in lieu of any other severance or termination pay to which Executive may be entitled following a Change in Control under any other Company plan, program, practice, arrangement or agreement providing severance benefits.

(b) Executive's entitlement to any other compensation or benefits following a Change of Control shall be determined in accordance with the Company's employee benefit plans and other applicable plans, programs, practices, arrangements or agreements then in effect. In particular, if Executive is eligible to retire on his Termination Date, any termination of Executive's employment pursuant to this Agreement shall not prevent his termination from being classified as a "retirement" for purposes of the Company's retirement plan, the SERP or any of its equity compensation plans.

2.3 Relocation Benefits. In the event of termination of Executive's employment other than as specified in Section 2.1(a), if Executive provides written notice to the Company within 90 days after the date of termination that Executive intends to relocate Executive's principal residence to another city and such relocation is completed within one year after the date of termination, the Company shall reimburse Executive for reasonable documented home finding and moving expenses in accordance with the Company's relocation policy as in effect from time to time. Executive shall present appropriate documentation to the Company in support of any reimbursement request hereunder.

3. Notice of Termination. Following a Change in Control, any purported termination of Executive's employment by the Company shall be communicated by Notice of Termination to Executive. For purposes of this Agreement, no such purported termination shall be effective without such Notice of Termination.

4. Contingent Cutback.

(a) Notwithstanding anything contained in this Agreement to the contrary, to the extent that the payments and benefits provided under this Agreement and benefits provided to, or for the benefit of, Executive under any other Company plan or agreement (such payments or benefits are collectively referred to as the "**Payments**") would be subject to the excise tax (the "**Excise Tax**") imposed under Section 4999 of the Code, the Payments shall be reduced (but not below zero) so that the value of all Payments equals 2.99 times Executive's "base amount," within the meaning of Section 280G(b)(3) of the Code and the applicable Treasury Regulations thereunder (the "**Safe Harbor Amount**") minus $1,000.00, but only if, by reason of such reduction (the "**Required Reduction**"), the Net After-Tax Benefit if such Required Reduction were made exceeds the Net After-Tax Benefit if such Required Reduction were not made. The "**Net After-Tax Benefit**" is defined as the value of the Payments net of all taxes imposed under Sections 1 and 4999 of the Code and under applicable state and local laws, determined by applying the highest marginal rate under Section 1 of the Code and under applicable state and local laws which applies to Executive's taxable income for the immediately preceding taxable year, or such rate(s) as Executive certifies as likely to apply in the relevant tax year(s).

(b) If a reduction is required pursuant to Section 4(a), unless Executive shall have given prior written notice specifying a different order to the Company to effectuate the Required Reduction, the Company shall reduce or eliminate the Payments by first reducing or eliminating those payments or benefits which are not payable in cash and then by reducing or eliminating cash payments, in each case in reverse order beginning with payments or benefits which are to be paid the farthest in time from the date of the Determination. Any notice given by Executive pursuant to the preceding sentence shall take precedence over the provisions of any other plan, program, practice, arrangement or agreement governing Executive's rights and entitlements to any benefits or compensation.

(c) An initial determination as to whether the Required Reduction shall take place pursuant to this Agreement and the calculation of such Required Reduction shall be made at the Company's expense by an accounting firm selected by the Company which is designated as one of the five largest accounting firms in the United States (the "**Accounting Firm**"). The Accounting Firm shall provide its determination (the "**Determination**") together with detailed supporting calculations and documentation to the Company and Executive within 10 days of the Termination Date, or such other time as requested by the Company and, if the Accounting Firm determines that no Excise Tax is payable by Executive with respect to a Payment or Payments, it shall furnish to the Executive an opinion reasonably acceptable to Executive that no Excise Tax will be imposed with respect to any such Payment or Payments. Within ten days of the delivery of the Determination to Executive, Executive shall have the right to dispute the Determination (the "**Dispute**"). If there is no Dispute, the Determination shall be binding, final and conclusive upon the Company and Executive subject to the application of Section 4(d) below.

(d) As a result of the uncertainty in the application of Sections 4999 and 280G of the Code, it is possible that the Payments to be made to, or provided for the benefit of, Executive either have been made or will not be made by the Company which, in either case, will be inconsistent with the limitations provided in Section 4(a) (hereinafter referred to as an "**Excess Payment**" or "**Underpayment**", respectively). If it is established, pursuant to a final determination of a court or an Internal Revenue Service (the "**IRS**") proceeding which has been finally and conclusively resolved, that an Excess Payment has been made, such Excess Payment shall be deemed for all purposes to be a loan to Executive made on the date Executive received the Excess Payment and Executive shall repay the Excess Payment to the Company on demand (but not less than ten days after written notice is received by Executive) together with interest on the Excess Payment at the applicable "federal short term rate" prescribed pursuant to Code Section 1274(d)(1)(C)(i) of the Code (hereinafter the "**Applicable Federal Rate**") from the date of Executive's receipt of such Excess Payment until the date of such repayment.

In the event that it is determined (i) by the Accounting Firm or the Company (which shall include the position taken by the Company, or together with its consolidated group, on its federal income tax return), (ii) pursuant to a determination by a court or the IRS, or (iii) upon the resolution to Executive's satisfaction of the Dispute, that an Underpayment has occurred, the Company shall pay an amount equal to the Underpayment to Executive within ten days of such determination or resolution together with interest on such amount at the Applicable Federal Rate from the date such amount would have been paid to Executive until the date of payment.

5. Successors; Nonalienation.

5.1 Successors.

(a) This Agreement shall be binding upon and shall inure to the benefit of the Company and its Successors and Assigns.

(b) This Agreement shall inure to the benefit of and be enforceable by Executive's legal personal representative.

5.2 Nonalienation. Neither this Agreement nor any right or interest hereunder shall be assignable or transferable by Executive, Executive's beneficiaries or legal representatives, except by will or by the laws of descent and distribution.

6. Applicable Law; Venue. This Agreement shall be governed and construed in accordance with the laws of the State of Delaware, without regard to conflicts of laws principles thereof. Any legal actions concerning the Agreement may be brought only in the United States district court for the Southern District of Texas, Houston Division.

7. Costs of Proceedings. Each Party shall pay its own costs and expenses in connection with any legal proceeding (including arbitration), relating to the interpretation of enforcement of any provision of this Agreement, except that the Company shall pay such costs and expenses, including attorneys' fees and disbursements, of Executive if Executive prevails in such proceeding.

8. Notice. For the purposes of this Agreement, notices and all other communications provided for in the Agreement (including the Notice of Termination) shall be in writing and shall be deemed to have been duly given when personally delivered or sent by certified mail, return receipt requested, postage prepaid, addressed to the respective addresses last given by each party to the other, provided that all notices to the Company shall be directed to the attention of the Board with a copy to the Secretary of the Company. All notices and communications shall be deemed to have been received on the date of delivery thereof or on the third business day after the mailing thereof, except that notice of change of address shall be effective only upon receipt.

9. Non-exclusivity of Rights. Subject to Section 2.2(a), nothing in this Agreement shall prevent or limit Executive's continuing or future participation in any benefit, bonus, incentive or other plan or program provided by the Company and for which Executive may qualify, nor shall anything herein limit or reduce such rights as Executive may have under any other agreements with the Company. Amounts which are vested benefits or which Executive is otherwise entitled to receive under any Company plan, program, practice or arrangement shall be payable in accordance with such plan, program, practice or arrangement except as explicitly modified by this Agreement.

10. Restrictive Covenants.

(a) In consideration of the provision to the Executive of the Severance Benefits, Executive agrees that, subject to Section 10(d) below, Executive will not at any time, except with the prior written consent of the Company, directly or indirectly, reveal to any person, entity or other organization (other than the Company or its employees, officers, directors or agents) or use for Executive's own benefit any Confidential Information. Notwithstanding anything in this Agreement to the contrary and subject to Section 10(d) below, (x) in the event that Executive becomes legally compelled to disclose any Confidential Information, Executive will provide the Company with prompt written notice so that the Company may seek a protective order or other appropriate remedy and (y) in the event that such protective order or other remedy is not obtained, Executive will furnish only that portion of such Confidential Information or take only such action as is legally required by binding order and Executive will exercise reasonable efforts to obtain reliable assurance that confidential treatment will be accorded for any such Confidential Information.

(b) During the period beginning on any Termination Date which occurs after a Change in Control and ending on the first anniversary of such Termination Date (the "**Restricted Period**"), Executive will not, without the Company's express written consent, directly or indirectly, solicit, induce or attempt to induce any employees, agents or consultants of the Company or its subsidiaries or affiliates to do anything from which Executive is restricted by reason of this Agreement nor will Executive, directly or indirectly, solicit, induce or aid others to solicit or induce any employees, agents or consultants of the Company or any of its subsidiaries or affiliates to terminate their employment or engagement with the Company or any of its subsidiaries or affiliates and/or to enter into an employment, agency or consultancy relationship with Executive or any other person or entity with whom Executive is affiliated.

(c) During the Restricted Period, Executive will not, without the Company's express written consent, directly or indirectly, own, manage, operate, control, render service to, or participate in the ownership, management, operation or control of any Competitor (as defined below) anywhere in the United States or in any non U.S. jurisdiction in which the Company is engaged or plans to engage in business as of the Termination Date; provided, however, that Executive will be entitled to own shares of stock of any corporation having a class of equity securities actively traded on a national securities exchange or the Nasdaq Stock Market which represent, in the aggregate, not more than 1% of such corporation's fully-diluted shares. For purposes of this Agreement, "**Competitor**" means any company, other entity or association or individual that directly or indirectly is engaged in (i) the business of oil or gas exploration or production or (ii) any other business in which the Company or any of its subsidiaries is engaged as of the Termination Date.

(d) Nothing in this Agreement or otherwise limits Executive's ability to communicate directly with and provide information, including documents, not otherwise protected from disclosure by any applicable law or privilege to the Securities and Exchange Commission ("**SEC**") or any other federal, state or local governmental agency or commission ("**Government Agencies**") regarding possible legal violations, without disclosure to the Company. The Company may not retaliate against Executive for any of these activities, and nothing in this Agreement or otherwise requires Executive to waive any monetary award or other payment that Executive might become entitled to from the SEC or any other Government Agency. Nothing in this Agreement or otherwise requires Executive to disclose any communications Executive may have had or information Executive may have provided to the SEC or any other Government Agencies regarding possible legal violations. In addition, notwithstanding anything to the contrary in this Agreement or otherwise, as provided for in the Defend Trade Secrets Act of 2016 (18 U.S.C. § 1833(b)), Executive will not be held criminally or civilly liable under any federal or state trade secret law for the disclosure of a trade secret that (i) is made (A) in confidence to a federal, state, or local government official, either directly or indirectly, or to an attorney, and (B) solely for the purpose of reporting or investigating a suspected violation of law; or (ii) is made in a complaint or other document filed in a lawsuit or other proceeding, if such filing is made under seal. Without limiting the foregoing, if Executive files a lawsuit for retaliation by Company for reporting a suspected violation of law, Executive may disclose the trade secret to her attorney and use the trade secret information in the court proceeding, if Executive (x) files any document containing the trade secret under seal, and (y) does not disclose the trade secret, except pursuant to court order.

11. Modification and Waiver. No provision of this Agreement may be modified, waived or discharged unless such waiver, modification or discharge is agreed to in writing and signed by Executive and the Company. No waiver by either party hereto at any time of any breach by the other party hereto of, or compliance with, any condition or provision of this Agreement to be performed by such other party shall be deemed a waiver of similar or dissimilar provisions or conditions at the same or at any prior or subsequent time. No agreement or representations, oral or otherwise, express or implied, with respect to the subject matter hereof have been made by either party which are not expressly set forth in this Agreement.

12. Withholding. Notwithstanding any other provision of this Agreement, the Company may, to the extent required by law, withhold federal, state and local income and other taxes from any payments due Executive hereunder.

13. Severability. The provisions of this Agreement shall be deemed severable and the invalidity or unenforceability of any provision shall not affect the validity or enforceability of the other provisions hereof.

14. Section 409A of the Code. Notwithstanding any provision to the contrary, all provisions of this Agreement shall be construed and interpreted to comply with Section 409A and the applicable Treasury Regulations thereunder and if necessary, any provision shall be held null and void to the extent such provision (or part thereof) fails to comply with Section 409A or the Treasury Regulations thereunder. For purposes of the limitations on nonqualified deferred compensation under Section 409A, each payment of compensation under this Agreement shall be treated as a separate payment of compensation for purposes of applying the deferral election rules and the exclusion for certain short-term deferral amounts under Section 409A. Any reimbursements or in-kind benefits provided under this Agreement that are subject to Section 409A shall be made or provided in accordance with the requirements of Section 409A, including, where applicable, the requirement that (i) any reimbursement is for expenses incurred during the period of time specified in the Agreement, (ii) the amount of expenses eligible for reimbursement, or in-kind benefits provided, during a calendar year may not affect the expenses eligible for reimbursement, or in-kind benefits to be provided, in any other calendar year, (iii) the reimbursement of an eligible expense will be made no later than the last day of the calendar year following the year in which the expense is incurred, and (iv) the right to reimbursement or in-kind benefits is not subject to liquidation or exchange for another benefit.

15. Definitions.

"**Accounting Firm**" shall have the meaning set forth in Section 4(c).

"**Accrued Compensation**" means all amounts earned or accrued through the Termination Date in accordance with Company policies but not paid as of the Termination Date, including (i) base salary, (ii) reimbursement for reasonable and necessary expenses incurred by the Executive on behalf of the Company during the period ending on the Termination Date, (iii) accrued and unused vacation pay, and (iv) earned but unpaid bonus amounts.

"**Applicable Federal Rate**" shall have the meaning set forth in Section 4(d).

"**Base Salary**" means the greater of Executive's annual base salary (i) at the rate in effect immediately prior to the Termination Date or (ii) at the highest rate in effect at any time during the 90-day period before the Change in Control.

"**Bonus Amount**" means the average of the annual cash bonuses paid or payable during the three full fiscal years ended before the Termination Date or, if greater, the three full fiscal years ended before the Change in Control (or, in each case, such lesser period for which annual cash bonuses were paid or payable to Executive); provided that, in the event Executive has not been employed by the Company for a full fiscal year, the Bonus Amount shall equal Executive's target annual cash bonus during the year in which the Termination Date occurs.

"**Cause**" means (i) Executive's willful failure or refusal to satisfactorily perform his duties or obligations in connection with his employment, (ii) Executive's having engaged in willful misconduct, gross negligence or a breach of fiduciary duty, or Executive's material breach of this Agreement or of any Company policy, (iii) Executive's conviction of, or a plea of nolo contendere to, (x) a felony or (y) any other criminal offense involving moral turpitude, fraud or dishonesty, (iv) Executive's unlawful use or possession of illegal drugs on the Company's premises or while performing his duties and responsibilities hereunder or (v) Executive's commission of an act of fraud, embezzlement or misappropriation, in each case, against the Company or any of its subsidiaries or affiliates, provided that, in each case (except for circumstances described in clauses (iii), (iv) or (v) above), the Company shall provide Executive with written notice specifying the circumstances alleged to constitute Cause, and, if such circumstances are susceptible to cure, Executive shall have 30 days following receipt of such notice to cure such circumstances.

A "**Change in Control**" shall be deemed to have occurred if (i) any "person", including a "group" (as such terms are used in Sections 13(d) and 14(d)(2) of the Exchange Act, but excluding the Company, any of its subsidiaries or any employee benefit plan of the Company or any of its subsidiaries or the Murphy Family) is or becomes the "beneficial owner" (as defined in Rule 13(d)(3) under the Exchange Act), directly or indirectly, of securities of the Company representing 25% or more of the combined voting power of the Company's then outstanding securities; (ii) a merger or other business combination, which has been approved by the stockholders of the Company, is consummated with or into another corporation a majority of the directors of which were not directors of the Company immediately prior to the merger and in which the stockholders of the Company immediately prior to the effective date of such merger own less than 50% of the voting power in such corporation; or (iii) a sale or other disposition of all or substantially all of the assets of the Company is consummated other than to an entity more than 50% of the voting power of which is owned, directly or indirectly, by the stockholders of the Company immediately after such sale or other disposition.

Notwithstanding anything contained in this Agreement to the contrary, if Executive's employment is terminated before a Change in Control and Executive reasonably demonstrates that such termination (i) was at the request of a third-party who has indicated an intention to take or has taken steps reasonably calculated to effect a

Change in Control and who effectuates a Change in Control (a “**Third-Party**”) or (ii) otherwise occurred in connection with, or in anticipation of, a Change in Control which actually occurs, then for all purposes of this Agreement, the date of a Change in Control with respect to Executive shall mean the date immediately before the date of such termination of Executive’s employment.

“**Code**” means the Internal Revenue Code of 1986, as amended from time to time.

“**Company Equity Awards**” shall have the meaning set forth in Section 2.1(b)(iii).

“**Competitor**” shall have the meaning set forth in Section 10(c).

“**Confidential Information**” means, without limitation and regardless of whether such information or materials are expressly identified as confidential or proprietary, (i) any and all non-public, confidential or proprietary information of the Company or any of its subsidiaries or affiliates, (ii) any information of the Company or any of its subsidiaries or affiliates that gives the Company or any of its subsidiaries or affiliates a competitive business advantage or the opportunity of obtaining such advantage, (iii) any information of the Company or any of its subsidiaries or affiliates the disclosure or improper use of which would reasonably be expected to be detrimental to the interests of the Company or any of its subsidiaries or affiliates and (iv) any trade secrets of the Company or any of its subsidiaries or affiliates. Confidential Information also includes any non-public, confidential or proprietary information about, or belonging to, any third- party that has been entrusted to the Company or any of its subsidiaries or affiliates. The term “Confidential Information” shall not include information that is or becomes generally available to the public other than as a result of an impermissible disclosure by Executive, or at Executive’s direction or is provided to Executive by an independent third-party that is under no obligation of confidentiality to the Company with respect to such information.

“**Determination**” shall have the meaning set forth in Section 4(c).

“**Dispute**” shall have the meaning set forth in Section 4(c).

“**Disability**” means, as determined by the Company in good faith, any medically determinable physical or mental impairment resulting in Executive’s inability to engage in any substantial gainful activity, where such impairment can be expected to result in death or can be expected to last for a continuous period of not less than 12 months.

“**Exchange Act**” means the Securities Exchange Act of 1934, as amended from time to time.

“**Excess Payment**” shall have the meaning set forth in Section 4(d).

“**Excise Tax**” shall have the meaning set forth in Section 4(a).

“**Good Reason**” means the occurrence of any of the following events without Executive’s consent: (i) a material reduction in Executive’s base salary, annual bonus opportunity or long-term incentive award opportunity, (ii) relocation of the geographic location of Executive’s principal place of employment by more than 50 miles from Executive’s principal place of employment, (iii) a material breach by the Company of this Agreement or (iv) a material reduction in Executive’s authority, duties or responsibilities, provided that, in each case, (A) Executive shall provide the Company with written notice specifying the circumstances alleged to constitute Good Reason within 90 days following the first occurrence of such circumstances, (B) the Company shall have 30 days following receipt of such notice to cure such circumstances, and (C) if the Company has not cured such circumstances within such 30-day period Executive shall terminate his employment not later than 60 days after the end of such 30-day period.

Any event or condition described in clauses (i) to (iv) above which occurs before a Change in Control but which Executive reasonably demonstrates (A) was at the request of a Third-Party, or (B) otherwise occurred in connection with, or in anticipation of, a Change in Control which actually occurs, shall constitute Good Reason for purposes of this Agreement notwithstanding that it occurred before the Change in Control and without regard to the notice and cure provisions hereof which shall not apply with respect to such event or condition.

“**Immediate Family**” of a person means such person’s spouse, children, siblings, mother-in-law and father-in-law, sons-in-law, daughters-in-law, brothers-in-law and sisters-in-law.

“**IRS**” shall have the meaning set forth in Section 4(d).

“**Murphy Family**” means (a) the C.H. Murphy Family Investments Limited Partnership, (b) the estate of C.H. Murphy, Jr., and (c) siblings of the late C.H. Murphy, Jr. and his and their respective Immediate Family.

“**Net-After-Tax Benefit**” shall have the meaning set forth in Section 4(a).

“**Notice of Termination**” means, following a Change in Control, a written notice of termination from the Company to Executive which indicates the specific termination of termination provision in this Agreement relied upon and which sets forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of Executive’s employment under the provision so indicated.

“**Payments**” shall have the meaning set forth in Section 4(a).

“**Release of Claims**” shall have the meaning set forth in Section 2(d).

“**Required Reduction**” shall have the meaning set forth in Section 4(a).

“**Restricted Period**” shall have the meaning set forth in Section 10(b).

“**Safe Harbor Amount**” shall have the meaning set forth Section 4(a).

“**Section 409A**” shall have the meaning set forth in Section 2.1(c).

“**Separation from Service**” shall have the meaning set forth in Section 2.1(c).

“**SERP**” means the Company’s Supplemental Executive Retirement Plan, as restated effective as of January 1, 2008.

“**SERP Liabilities**” shall have the meaning set forth in Section 2.2(f).

“**Severance Amounts**” shall have the meaning set forth in Section 2.1(d).

“**Severance Benefits**” means the amounts and benefits paid or provided pursuant to Section 2.1(b).

“**Specified Employee**” shall have the meaning set forth in Section 2.1(c).

“**Successors and Assigns**” means a corporation or other entity which has acquired or succeeded to all or substantially all or the assets and business of the Company (including this Agreement) whether by operation of law or otherwise.

“**Termination Date**” shall mean in the case of Executive’s death, Executive’s date of death, in the case of a resignation by Executive from Executive’s employment with the Company, the last day of Executive’s employment and in all other cases involving a termination of Executive’s employment with the Company, the date specified in the Notice of Termination; provided, however, that if Executive’s employment is terminated by the Company due to Disability, the date specified in the Notice of Termination shall be at least 30 days from the date the Notice of Termination is given to Executive, provided that Executive shall not have returned to the full-time performance of Executive’s duties during such period of at least 30 days.

“**Third-Party**” shall have the meaning set forth in the definition of Change in Control.

“**Trust**” shall have the meaning set forth in Section 2.1(f).

“**Underpayment**” shall have the meaning set forth in Section 4(d).

16. Entire Agreement. This Agreement constitutes the entire agreement between the parties hereto and supersedes all prior agreements, if any, understandings and arrangements, oral or written, between the parties hereto with respect to the subject matter hereof.

[Remainder of page intentionally left blank; signature page to follow.]

IN WITNESS WHEREOF, the Company has caused this Agreement to be executed by its duly authorized officer and the Executive has executed this Agreement as of the day and year first above written.

MURPHY OIL CORPORATION

By: ______________________________

Name: [•]

Title: [•]

EXECUTIVE

By: ______________________________

Name: [•]

Title: [•]

Exhibit 10.33

Execution Version

FIRST AMENDMENT TO

CREDIT AGREEMENT

dated as of* February 6, 2025 *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 HERETO

FIRST AMENDMENT TO CREDIT AGREEMENT

THIS FIRST AMENDMENT TO CREDIT AGREEMENT (this "First Amendment") dated as of February 6, 2025 is among **MURPHY OIL CORPORATION**, a Delaware corporation (the "Company"), **MURPHY EXPLORATION & PRODUCTION COMPANY – INTERNATIONAL**, a Delaware corporation ("Expro-Intl."), **MURPHY OIL COMPANY LTD.**, a Canadian corporation ("MOCL" and, together with the Company and Expro-Intl., collectively, the "Borrowers"); **JPMORGAN CHASE BANK, N.A.**, as administrative agent (in such capacity, together with its successors in such capacity, the "Administrative Agent") for the lenders party to the Credit Agreement referred to below (collectively, the "Lenders"); and the undersigned Lenders.

R E C I T A L S

A. The Borrowers, the Administrative Agent and the Lenders are parties to that certain Credit Agreement dated as of October 7, 2024 (as amended, supplemented or otherwise modified prior to the date hereof, the "Credit Agreement"), pursuant to which the Lenders have made certain extensions of credit available to the Borrowers.

B. The Borrowers have requested and the undersigned Administrative Agent and Lenders have agreed, subject to the terms and conditions set forth herein, to amend certain provisions of the Credit Agreement as set forth herein.

C. NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree as follows:

Section 1. Defined Terms. Each capitalized term used herein but not otherwise defined herein has the meaning given such term in the Credit Agreement (as amended hereby). Unless otherwise indicated, all references to Sections and Articles in this First Amendment refer to Sections and Articles of the Credit Agreement.

Section 2. Amendments to Credit Agreement.

2.1 Amendment to Cover Page. The cover page to the Credit Agreement is hereby amended and restated in its entirety to read as set forth on Exhibit A to this First Amendment.

2.2 Amendments to Section 1.01.

(a) Each of the following defined terms is hereby amended and restated in its entirety to read as follows:

"Agreement" means this Credit Agreement, as amended by the First Amendment and as the same may from time to time be amended, modified, supplemented or restated.

"Lead Arrangers" means JPMorgan Chase Bank, N.A., BofA Securities, Inc., Capital One, National Association, MUFG Bank, Ltd., Scotiabank, Regions

Capital Markets, a Division of Regions Bank, and Bank OZK, in their respective capacities as co-lead arrangers and joint bookrunners hereunder.

(b) The following defined term is hereby added to Section 1.01 where alphabetically appropriate, to read as follows:

"First Amendment" means that certain First Amendment to Credit Agreement, dated as of February 6, 2025, by and among the Borrowers, the Administrative Agent and the Lenders party thereto.

2.3 Amendment to Section 6.13. Section 6.13 is hereby amended and restated in its entirety to read as follows:

Section 6.13 New Accounts Prior to the Investment Grade Rating Date. Prior to the Investment Grade Rating Date, the Company will not, and will not permit any Subsidiary to, open or otherwise establish or maintain, or deposit, credit or otherwise transfer any Cash Receipts, securities, financial assets or any other property into, any Deposit Account, Securities Account or Commodity Account (other than any Excluded DDA) other than a Deposit Account, Securities Account or Commodity Account listed on Schedule 5.14, which is maintained with the Administrative Agent or a Lender or another financial institution reasonably acceptable to the Administrative Agent. The Company may supplement Schedule 5.14 to include additional Deposit Accounts, Securities Accounts or Commodity Accounts maintained with the Administrative Agent or a Lender or another financial institution reasonably acceptable to the Administrative Agent by delivering to the Administrative Agent a supplement to Schedule 5.14 clearly marked as such (which supplement shall be promptly furnished to the Lenders).

2.4 Amendment to Schedule 5.14. Schedule 5.14 is hereby amended and restated in its entirety to read as set forth on Schedule 5.14 to this First Amendment.

Section 3. Conditions Precedent. This First Amendment shall not become effective until the date on which each of the following conditions is satisfied (or waived in accordance with Section 10.02 of the Credit Agreement) (the "First Amendment Effective Date"):

3.1 The Administrative Agent, the Lenders and the Lead Arrangers shall have received all fees and other amounts due and payable to each such Person on or prior to the First Amendment Effective Date, including to the extent invoiced, reimbursement or payment of all out-of-pocket expenses required to be reimbursed or paid by the Borrowers pursuant to the Credit Agreement (including, without limitation, the fees and expenses of Paul Hastings LLP, as special counsel to the Administrative Agent).

3.2 The Administrative Agent shall have received from the Required Lenders and the Borrowers, counterparts of this First Amendment signed on behalf of such Persons.

3.3 The Administrative Agent shall have received such other documents as the Administrative Agent or special counsel to the Administrative Agent may reasonably request.

3.4 No Default shall have occurred and be continuing.

The Administrative Agent is hereby authorized and directed to declare the occurrence of the First Amendment Effective Date when it has received documents confirming compliance with the conditions set forth in this Section 3 or the waiver of such conditions as agreed to by the Lenders pursuant to Section 10.02(b) of the Credit Agreement. Such declaration shall be final, conclusive and binding upon all parties to this First Amendment for all purposes. For purposes of determining compliance with the conditions specified in this Section 3, each Lender shall be deemed to have consented to, approved or accepted or to be satisfied with, each document or other matter required thereunder to be consented to or approved by or acceptable or satisfactory to a Lender unless the Administrative Agent shall have received written notice from such Lender prior to the proposed First Amendment Effective Date specifying its objection thereto.

Section 4. Miscellaneous.

4.1 Confirmation. The provisions of the Credit Agreement, as amended by this First Amendment, shall remain in full force and effect following the effectiveness of this First Amendment.

4.2 Ratification and Affirmation; Representations and Warranties. Each Borrower hereby: (a) acknowledges the terms of this First Amendment; (b) acknowledges, ratifies and affirms its obligations and continued liability under, the Credit Agreement and the other Loan Documents to which it is party and agrees that the Credit Agreement remains in full force and effect, except as expressly amended hereby, after giving effect to the amendments and waivers contained herein; (c) agrees that the terms “Agreement”, “this Agreement”, “herein”, “hereinafter”, “hereto”, “hereof” and words of similar import, as used in the Credit Agreement, shall, unless the context otherwise requires, refer to the Credit Agreement, as amended hereby, and the term “Credit Agreement” as used in the other Loan Documents shall mean the Credit Agreement, as amended hereby; and (d) represents and warrants to the Lenders that as of the date hereof, after giving effect to the terms of this First Amendment: (i) all of the representations and warranties contained in the Credit Agreement are true and correct, unless such representations and warranties are stated to relate to a specific earlier date, in which case, such representations and warranties shall continue to be true and correct as of such earlier date and (ii) no Default has occurred and is continuing.

4.3 Counterparts. This First Amendment may be executed by one or more of the parties hereto in any number of separate counterparts, and all of such counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of an executed counterpart of a signature page of this First Amendment by telecopy, emailed pdf or any other electronic means that reproduces an image of the actual executed signature page shall be effective as delivery of a manually executed counterpart of this First Amendment.

4.4 NO ORAL AGREEMENT. THIS FIRST AMENDMENT, THE CREDIT AGREEMENT AND THE OTHER LOAN DOCUMENTS EXECUTED IN CONNECTION HEREWITH AND THEREWITH REPRESENT THE FINAL AGREEMENT AMONG THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR,

CONTEMPORANEOUS, OR UNWRITTEN ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO ORAL AGREEMENTS BETWEEN THE PARTIES.

4.5 GOVERNING LAW. THIS FIRST AMENDMENT (INCLUDING, BUT NOT LIMITED TO, THE VALIDITY AND ENFORCEABILITY HEREOF) SHALL BE CONSTRUED IN ACCORDANCE WITH AND GOVERNED BY THE LAWS OF THE STATE OF NEW YORK AND EACH BORROWER HEREBY IRREVOCABLY AND UNCONDITIONALLY SUBMITS, FOR ITSELF AND ITS PROPERTY, TO THE NONEXCLUSIVE JURISDICTION OF THE SUPREME COURT OF THE STATE OF NEW YORK SITTING IN NEW YORK COUNTY AND OF THE UNITED STATES DISTRICT COURT OF THE SOUTHERN DISTRICT OF NEW YORK, AND ANY APPELLATE COURT FROM ANY THEREOF, IN ANY ACTION OR PROCEEDING ARISING OUT OF OR RELATING TO THE CREDIT AGREEMENT OR THIS FIRST AMENDMENT, OR FOR THE RECOGNITION OR ENFORCEMENT OF ANY JUDGMENT, AND EACH OF THE PARTIES HERETO IRREVOCABLY AND UNCONDITIONALLY AGREES THAT ALL CLAIMS IN RESPECT OF ANY SUCH ACTION OR PROCEEDING MAY BE HEARD AND DETERMINED IN SUCH NEW YORK STATE OR, TO THE EXTENT PERMITTED BY LAW, IN SUCH FEDERAL COURT. EACH OF THE PARTIES HERETO AGREES THAT A FINAL JUDGMENT IN ANY SUCH ACTION PROCEEDING SHALL BE CONCLUSIVE AND MAY BE ENFORCED IN OTHER JURISDICTIONS BY SUIT ON THE JUDGMENT OR IN ANY OTHER MANNER PROVIDED BY LAW. NOTHING IN THE CREDIT AGREEMENT OR THIS FIRST AMENDMENT SHALL AFFECT ANY RIGHT THAT THE ADMINISTRATIVE AGENT OR ANY LENDER MAY OTHERWISE HAVE TO BRING ANY ACTION OR PROCEEDING RELATING TO THE CREDIT AGREEMENT OR THIS FIRST AMENDMENT AGAINST ANY BORROWER OR ITS PROPERTIES IN THE COURTS OF ANY JURISDICTION.

4.6 Successors and Assigns. This First Amendment shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns.

4.7 Loan Document. This First Amendment is a “Loan Document” as defined and described in the Credit Agreement, and all of the terms and provisions of the Credit Agreement relating to Loan Documents shall apply hereto.

4.8 Severability. Any provision of this First Amendment held to be invalid, illegal or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such invalidity, illegality or unenforceability without affecting the validity, legality and enforceability of the remaining provisions hereof; and the invalidity of a particular provision in a particular jurisdiction shall not invalidate such provision in any other jurisdiction.

[SIGNATURES BEGIN NEXT PAGE]

IN WITNESS WHEREOF, the parties hereto have caused this First Amendment to be duly executed as of the date first written above.

MURPHY OIL CORPORATION

By: ________________________
Name: Leyster Jumawan
Title: Vice President and Treasurer

MURPHY EXPLORATION & PRODUCTION COMPANY - INTERNATIONAL

By: ________________________
Name: Leyster Jumawan
Title: Vice President and Treasurer

MURPHY OIL COMPANY LTD.

By: ________________________
Name: Leyster Jumawan
Title: Vice President and Treasurer

JPMORGAN CHASE BANK, N.A., as
Administrative Agent and a Lender

By: ________________________
Name: Sofia Barrera Jaime
Title: Vice President

BANK OF AMERICA, N.A., as a Lender

By: ________________________________
Name: Tommy Nguyen
Title: Vice President

THE BANK OF NOVA SCOTIA,
HOUSTON BRANCH, as a Lender

By: __
Name: Sam Cutler
Title: Director

CAPITAL ONE, NATIONAL ASSOCIATION, as a Lender

By: ________________________

Name: Lyle Levy

Title: Director

MUFG BANK, LTD., as a Lender

By: __ Name: Todd Vaubel
Title: Authorized Signatory

SUMITOMO MITSUI BANKING CORPORATION, as a Lender

By:______________________

Name: Alkesh Nanavaty

Title: Executive Director

STANDARD CHARTERED BANK, as a Lender

By: ________________________
Name: Kristopher Tracy
Title: Director, Financing Solutions

TEXAS CAPITAL BANK, as a Lender

By: ________________________
Name: Gabriel X. Garcia
Title: Managing Director

MORGAN STANLEY BANK, N.A., as a Lender

By: ________________________
Name: Aaron McLean
Title: Authorized Signatory

BANK OZK, as a Lender

By: ________________________
Name: Charlie Davis
Title: Managing Director

CREDIT AGREEMENT

dated as of October 7, 2024

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 HERETO

BANK OF AMERICA, N.A., CAPITAL ONE, NATIONAL ASSOCIATION, MUFG BANK, LTD. AND THE BANK OF NOVA SCOTIA, HOUSTON BRANCH, AND
REGIONS BANK
as Co-Syndication Agents

and

SUMITOMO MITSUI BANKING CORPORATION,
as Documentation Agent

JPMORGAN CHASE BANK, N.A., BOFA SECURITIES, INC., CAPITAL ONE, NATIONAL ASSOCIATION, MUFG BANK, LTD., THE BANK OF NOVA SCOTIA, HOUSTON BRANCH, REGIONS CAPITAL MARKETS, A DIVISION OF REGIONS BANK, AND BANK OZK
as Co-Lead Arrangers and Joint Bookrunners

Exhibit A

Schedule 5.14
to Credit Agreement

ACCOUNTS

Account	**Financial Institution or Intermediary**	**Account Number**	**Account Type**	**Excluded DDA (Y/N)**
Murphy Oil Corporation - General (Wires)	Bank of America, N. A., New York, NY	USD A/C # 004451259985	Depository Account	Y
Murphy Oil Corporation - CDA (ACH/Check)	Bank of America, N. A., New York, NY	USD A/C # 003359985473	Depository Account	Y
Murphy Oil Corporation - Lease Rental	Bank of America, N. A., New York, NY	USD A/C # 003359985481	Depository Account	Y
Murphy Exploration & Production Company	Bank of America, N. A., New York, NY	USD A/C # 004451259862	Depository Account	Y
Canam Offshore Limited	Bank of America, N. A., New York, NY	USD A/C # 004451259859	Depository Account	Y
Murphy Oil Corporation	BancorpSouth, El Dorado, AR	USD A/C # 6400074412/ 6400074404	Marine Land Co/ Caledonia Land Co	N
Murphy Brasil Exploracao E. Producao De Petroleo E Gas Ltda.	Bank of America, Sao Paulo, Brazil	BRL A/C #11057015	Depository Account	N
Canam Brunei Oil Ltd.	J. P. Morgan Chase Bank Berhad Kuala Lumpur, Malaysia	USD A/C # 0076953752	Depository Account	N
Murphy Oil Corporation	Capital One Bank N. A.	USD A/C # 4670140461	Money Market Cash Account	N
Murphy Oil Corporation	J. P. Morgan Chase Bank, New York, New York	USD A/C # 325-008361	Depository Account	N
New Murphy Oil (UK) Corporation	Bank of America, N. A., New York, NY	USD A/C # 004451259901	Depository Account	Y
MP Gulf of Mexico, LLC	Bank of America, N. A., New York, NY	USD A/C # 4451312783	Depository Account	Y
MP Gulf of Mexico, LLC	Bank of America, N. A., New York, NY	Controlled Disbursement USD A/C # 3359992560	Controlled Disbursement Account	N
Murphy Sur S de RL de CV	Bank of America Mexico, S. A., Mexico	USD A/C# 14633028	Depository Account	N

Account	Financial Institution or Intermediary	Account Number	Account Type	Excluded DDA (Y/N)
Murphy Sur S de RL de CV	Bank of America Mexico, S. A., Mexico	MXN A/C# 14633010	Depository Account	N
Murphy Sur S de RL de CV	Grupo Financiero Banorte, S.A.B de C.V.	MXN A/C# 1044029462	Depository Account	N
Murphy Netherlands Holdings BV	Bank of America Merrill Lynch Intl Ltd., Amsterdam	USD A/C # 20451013	Depository Account	N
Murphy Netherlands Holdings II BV	Bank of America Merrill Lynch Intl Ltd., Amsterdam	USD A/C # 20452011	Depository Account	N
Murphy Nha Trang Oil Co., Ltd.	J. P. Morgan Chase Bank Ho Chi Minh Branch, Vietnam	USD A/C # 0076958900 USD A/C # 0076958206 VND A/C # 0076958205	Depository Account	N
Murphy Phuong Nam Oil Co., Ltd.	J. P. Morgan Chase Bank Ho Chi Minh Branch, Vietnam	USD A/C # 0076958246 VND A/C # 0076958245	Depository Account	N
Murphy Cuu Long Bac Oil Co., Ltd.	J. P. Morgan Chase Bank Ho Chi Minh Branch, Vietnam	USD A/C # 0076958910 USD A/C # 0076958288 VND A/C # 0076958301	Depository Account	N
Murphy Cuu Long Tay Oil Co., Ltd.	J. P. Morgan Chase Bank Ho Chi Minh Branch, Vietnam	USD A/C # 0076958920 USD A/C # 0076958392 VND A/C # 0076958391	Depository Account	N
Murphy Oil Corporation	J. P. Morgan Chase Bank, New York, NY	USD A/C # 5029438	Money Market Cash Account	N
Murphy Oil Corporation	Regions Bank	USD A/C # 0179852122	Money Market Cash Account	N
Murphy Oil Corporation	Bank of America, New York, NY	USD A/C # 5S4-04P36-1-7 EJE	Money Market Cash Account	N
Muprhy Oil Corporation	MUFG / Union Bank	USD A/C # 0820000973	Money Market Cash Account	N
Murphy Oil Corporation	Cadence Bank, El Dorado, AR	USD A/C # 78660842	Money Market Cash Account	N
Murphy Oil Corporation	Sumitomo Mitsui Banking Corporation (SMBC)	USD A/C # 370823	Money Market Cash Account	N
Murphy Australia Oil Pty. Ltd.	J. P. Morgan Chase Bank, Sydney, Australia	AUD A/C # 083602700 USD A/C # 0083602735	Depository Account	N

Account	Financial Institution or Intermediary	Account Number	Account Type	Excluded DDA (Y/N)
Murphy Australia AC/P58 Oil Pty Ltd.	J. P. Morgan Chase Bank, Sydney, Australia	USD A/C # 0083602882	Depository Account	N
Murphy Petroleum Ltd.	Bank of America NA London, UK	GBP A/C # 80451017 USD A/C # 80451025	Depository Account	N
MURCO Petroleum Ltd.	Bank of America NA London, UK	GBP A/C # 80449020 USD A/C # 80449012	Depository Account	N
Murphy Oil Corporation	MUFG / Union Bank	General USD A/C # 0021420914	Depository Account	N
Murphy Spain Oil Company	Bank of America Merrill Lynch Intl Ltd.	EUR A/C # ES79 1485 0001 0900 3663 1014	Depository Account	N
Murphy Exploration & Production Company – USA/Y Bar Ranch Ltd.	JP Morgan Chase Bank, N.A.	USD A/C # 528207496	Escrow Account	Y
Murphy Oil Corporation	Scotiabank, Ontario, Canada	CDN A/C # 129890008818	Depository Account	N
Murphy Oil Company Ltd.	Scotiabank, Ontario, Canada	CDN A/C # 10009 0439118 USD A/C # 129898926913	Depository Account	N
Murphy Oil Company Ltd.	Scotiabank, Ontario, Canada	CDN A/C # 129890007013 USD A/C # 129890349518	Pool Accounts	N
Murphy Canada Ltd.	Scotiabank, Ontario, Canada	CDN A/C # 12989 0003816 USD A/C # 12989 0350311	Depository Account	N
Murphy Oil Canada	Scotiabank, Ontario, Canada	CDN A/C # 12989 0005010	Depository Account	N
Murphy Oil Company Ltd.	Scotiabank, Ontario, Canada	USD A/C # 800-50673	Investment Account	N
Murphy Oil Company Ltd.	MUFG Bank, Ltd.	USD A/C #0820001619	Investment Account	N
Murphy Oil Company Ltd.	Scotiabank, Ontario, Canada	CDN A/C # 78047309-14 CDN A/C # 78047311-10 CDN A/C # 78047312-19 CDN A/C # 78047308-15 CDN A/C # 78049077-10	Trust Accounts	N

Account	Financial Institution or Intermediary	Account Number	Account Type	Excluded DDA (Y/N)
Murphy Exploration & Production Company - International	Bank of America, N. A., New York, NY	USD A/C # 4451452041	Depository Account	Y
Murphy Oil Corporation - Royalty (ACH/Check	Bank of America, N. A., New York, NY	USD A/C # 4451688857	Depository Account	N
MP Gulf of Mexico, LLC - Royalty (ACH/Check)	Bank of America, N. A., New York, NY	USD A/C # 4451688860	Depository Account	N
Murphy CI-102 Oil Co., LTD	Standard Chartered Bank	USD A/C # 3582028403001 XOF A/C # 01-001-204000-00	Depository Account	N
Murphy CI-103 Oil Co., LTD	Standard Chartered Bank	USD A/C # 3582028404001 XOF A/C # 01-001-203951-00	Depository Account	N
Murphy CI-502 Oil Co., LTD	Standard Chartered Bank	USD A/C # 3582028405001 XOF A/C # 01-001-203997-00	Depository Account	N
Murphy CI-531 Oil Co., LTD	Standard Chartered Bank	USD A/C # 3582028406001 XOF A/C # 01-001-203994-00	Depository Account	N
Murphy CI-709 Oil Co., LTD	Standard Chartered Bank	USD A/C # 3582028408001 XOF A/C # 01-001-203993-00	Depository Account	N
Murphy Oil Corporation	Standard Chartered Bank	USD A/C #3582028099001	Depository Account	N
Murphy Oil Corporation	Bank OZK	USD A/C #2804851771	Depository Account	N
Murphy Oil Corporation	Bank of America, New York, NY	USD A/C #4451938057	Controlled Disbursement Account	N
Murphy Oil Corporation	Texas Capital Bank	USD A/C #2400079580	Depository Account	N

MURPHY
OIL CORPORATION

We believe in providing energy that empowers people.

INSIDER TRADING POLICY

Exhibit 19.1

POLICY STATEMENT

It is the Company's policy to comply with state and federal laws regarding trading in Company Securities ("Company Stock") as well as the dissemination and use of Material Nonpublic Information ("MNPI"). As such, it is the Company's practice to require directors, officers and employees to obtain pre-clearance prior to trading in Company Stock; to prohibit those who are aware of MNPI from trading in Company Stock; and to prohibit disclosing MNPI to anyone who may trade in Company Stock on the basis of that information.

Capitalized terms used herein are defined at the end of this Policy.

SCOPE

This Policy applies to: (1) all directors and officers of the Company, (2) Company employees, contractors or consultants that have access to MNPI (both (1) and (2) are referred to in this Policy as an "Employee"), and (3) Family Members and Controlled Entities. Every Employee is responsible for compliance with this Policy by their Family Members and Controlled Entities.

This Policy is separate and in addition to the Company's Code of Conduct and Reg FD Policy and is intended to complement them regarding trading in Company Stock as well as the disclosure of MNPI.

TRANSACTIONS SUBJECT TO THIS POLICY

This Policy applies to Transactions involving the Company's Stock.

PROHIBITED CONDUCT

Except as provided herein, every Employee, Family Member or Controlled Entity must obtain Pre-Clearance prior to entering into a Transaction involving Company Stock.

Even if Pre-Clearance is obtained, no Employee, Family Member or Controlled Entity that is aware of, or has access to, MNPI may directly or indirectly:

- Engage in Transactions in Company Stock;
- Recommend the purchase or sale of any Company Stock;
- Disclose MNPI to anyone; including anyone within the Company whose job does not require them to have that information. *(For additional guidance regarding Confidential Information and MNPI see Murphy's Code of Conduct as well as the Reg FD Policy)*; or

- Assist anyone engaged in the above activities.

PRE-CLEARANCE

The Company has established the following procedure every Employee, Family Member or Controlled Entity must follow to trade in Company Stock. Unless a Transaction is covered by an exception in this Policy, this procedure must be followed every time.

Every Employee, Family Member and Controlled Entity must obtain a written Pre-Clearance approval from the General Counsel prior to any Transaction or gift involving Company Stock.

Requests for Pre-Clearance should be submitted to the General Counsel or the General Counsel's designee on the day of the Transaction. The General Counsel will consider the request and either approve it or determine it is not allowable under this Policy.

Each request for Pre-Clearance must include the following information for each requestor, corresponding Family Member or Controlled Entity: (1) whether they have knowledge of, or access to, any MNPI, and if so, include a detailed description, and (2) whether any have engaged in any non-exempt "opposite-way" transactions within six (6) months prior to the request.

If Pre-Clearance is granted, when required by the SEC, the requestor must coordinate with the Company to report the Transaction on an appropriate Form 4 or Form 5. The requestor should also be prepared to comply with SEC Rule 144 and coordinate with their broker to file a Form 144, if necessary, at the time the Transaction.

Contact information:

E. Ted Botner – General Counsel Phone
(281) 675-9000
Email: Ted_Botner@murphyoilcorp.com

Tricia M. Hammons – Director, Governance & Legal Services Phone
(281) 675-9000
Email: Tricia_Hammons@murphyoilcorp.com

RESTRICTIONS ON PRE-CLEARANCE

Pre-Clearance for any Transaction will not be granted when the requestor has access to MNPI, during a Blackout Period, or other Non-Trading Window.

For Pre-Clearance requests involving stock options or stock appreciation rights, if the request is made prior to 10a.m. CT on the desired trading day, and approved, the request will be processed using the prior trading day's average high and low stock price.

Pre-Clearance may be granted after MNPI becomes Publicly Disclosed. *Once information is Publicly Disclosed it is still necessary to afford the investing public with sufficient time to absorb the information.* As a general rule, information should not be considered fully absorbed by the marketplace until the third trading day after the information is released. For example, if the Company were to make an announcement on a Wednesday, trading is not permitted until the following Monday. Depending on the circumstances regarding the release of specific MNPI, the Company may determine that a longer period should apply.

MATERIAL NONPUBLIC INFORMATION REGARDING OTHER COMPANIES

This Policy extends to material nonpublic information relating to other companies. This includes the Company's customers, vendors, suppliers or venture partners when that information is obtained in the course of an Employee's duties on behalf of the Company. Such information should be treated with the same care required with respect to Company's confidential information.

Except as set forth in this Policy, no Employee who learns about material nonpublic information relating to other companies with which the Company does business, may trade in that company's Stock until the information becomes public or is no longer material.

TRANSACTIONS AFTER LEAVING THE COMPANY

This Policy will continue to apply until the later of (a) 90 days following an Employee's departure and (b) the end of the first Blackout Period that begins after the Employee has left the Company.

In addition to these restrictions, no Employee that leaves the Company with knowledge of MNPI may trade in Company Stock until that information has become public or is no longer material.

PROHIBITED TRANSACTIONS

No Employee may engage in any of the following Transactions involving Company Stock:

Short-Term Trading/Opposite Way Trades

No Employee who purchases Company Stock in the open market may sell Company Stock of the same class during the six (6) months following the purchase (or vice versa). *Note: Securities* *regulation Section 16(b) requires company insiders to return any profits made from the purchase and sale of Company Stock if both transactions occur within a six-month period.*

Short Sales
The sale of Company Stock that the seller does not own. *Note: Section 16(c) of the Exchange Act prohibits officers and directors from engaging in short sales. Short sales arising from certain types of hedging transactions are governed by the paragraph captioned "Hedging Transactions."*

Publicly-Traded Options
Transactions in put options, call options or other derivative securities on an exchange or in any other organized market. *For positions arising from certain types of hedging transactions, see the "Hedging Transactions" section.*

Hedging Transactions
Transactions including those involving options, puts, calls, prepaid variable forward contracts, equity swaps, collars and exchange funds or other derivatives, that are designed to hedge or speculate on any change in the market value of the Company's Stock.

SPECIAL CONDITIONS FOR SPECIFIC TRANSACTIONS

Margin Accounts and Pledged Stock
As noted in the Company's Corporate Governance Guidelines, a director or officer may not pledge Company Stock (including by purchasing Company Stock on margin or holding Company Stock in a margin account) until they have achieved the requisite stock ownership target specified in the Company's stock ownership guidelines. Once such stock ownership target has been achieved, a director or officer is permitted to pledge Company Stock in compliance with applicable law (including disclosure of such pledging in the Company's proxy statement as required by SEC regulations), provided, that Company Stock required to meet the applicable ownership target remains unpledged. Pledging of shares should be disclosed to the General Counsel before the pledges take place.

Standing and Limit Orders
Except for standing or limit orders under approved Rule 10b5-1 Plans, the Company discourages placing standing or limit orders on Company Stock. If an Employee desires to use a standing order or limit order, the order should be limited to short duration and should otherwise comply with the *Pre-Clearance procedures* outlined in this Policy.

10b5-1 Plans

Rule 10b5-1 under the Exchange Act provides an affirmative defense from insider trading liability. In order for this defense to be available, a person must enter into a written plan (a “10b5-1 Plan”) that meets the criteria specified in Rule 10b5-1. If the 10b5-1 Plan meets these requirements, the Employee may Transact in Company Stock pursuant to the 10b5-1 Plan while in possession of MNPI and during a Blackout Period or other Non-Trading Window.

Entry into a Rule 10b5-1 Plan is subject to the Pre-Clearance procedures outlined in this Policy and, to the extent applicable, compliance with the Company’s stock ownership guidelines. All Pre-Clearance requests must be made outside of a Blackout Period and at a time when the requestor is not in possession of MNPI.

10b5-1 Plan Requirements

Each 10b5-1 Plan must be in writing and signed by the Employee, and the Employee must provide a copy to the Company. A 10b5-1 Plan must not permit an Employee to exercise any subsequent influence over how, when or whether to effect purchases or sales. The Employee must act in good faith at the time the 10b5-1 Plan is adopted and with respect to the 10b5-1 Plan through its duration. In addition, each 10b5-1 Plan entered into by a director or officer must include a representation certifying that (a) such person is not in possession of material non- public information about the Company or Company Stock, and (b) the 10b5-1 Plan is being adopted in good faith and not as part of a plan to evade the prohibitions of Rule 10b-5.

Each 10b5-1 Plan must provide for delayed effectiveness after adoption or amendment (a “Cooling-Off Period”). For directors or officers, the 10b5-1 Plan must specify that trades cannot begin until the later of (a) 90 days after the date of adoption or amendment under the 10b5-1 Plan and (b) 2 business days following the Company’s filing of a quarterly or annual report covering the financial reporting period in which the 10b5-1 Plan was adopted or amended (but in no event later than 120 days after the adoption or amendment of the 10b5-1 Plan).

Amendment, Suspension and Termination

Amendments, suspensions, and terminations of 10b5-1 Plans must be approved in advance by the General Counsel or his or her designee. In addition, an Employee may not voluntarily amend a 10b5-1 Plan during a Blackout Period or other Non-Trading Window or while in possession of MNPI.

Mandatory Suspension

Each 10b5-1 Plan must provide for suspension of trades under such plan if legal, regulatory or contractual restrictions are imposed on the Employee, or if this Policy is amended, or other events occur, that would prohibit sales under the 10b5-1 Plan.

Only One Plan in Effect at Any Time

Subject to certain exceptions, an Employee may have only one 10b5-1 Plan in effect at any time. An Employee may adopt a new 10b5-1 Plan to replace an existing 10b5-1 Plan before the scheduled termination date of such existing 10b5-1 Plan, so long as the first scheduled trade under the new 10b5-1 Plan does not occur until after all trades under the existing 10b5-1 Plan are completed or expire without execution (subject to any Cooling-Off Periods).

Notice of Trades

Each 10b5-1 Plan entered into by an Employee subject to Section 16 filing requirements must provide that the broker will provide notice of any trades under the 10b5-1 Plan to the Employee in sufficient time to allow for the Employee to make timely filings under the Exchange Act.

Company Disclosures

The Company will disclose in its quarterly and annual reports the material terms of the 10b5-1 Plans adopted or terminated (which includes modifications) by directors or officers, including the identity of the person, the date of adoption or termination, the duration of the trading arrangement and the aggregate number of Company Stock covered under the 10b5-1 Plan.

EXCEPTIONS

This Policy does not apply to the following Transactions:

Restricted Stock Awards

This Policy does not apply to the vesting of restricted stock, or the exercise of a tax withholding right pursuant to which an Employee elects to have the Company withhold shares of stock to satisfy tax withholding requirements upon the vesting of any restricted stock. The Policy does apply; however, to any market sale of restricted stock.

401(k) Plan

This Policy does not apply to purchases of Company Stock in the Company’s 401(k) plan resulting from a payroll deduction election. This Policy does apply; however, to other elections made under the 401(k) plan, including: (a) an election to increase or decrease the percentage of periodic contributions that will be allocated to the Company stock fund; (b) an election to make an intra-plan transfer of an existing account balance into or out of the Company stock fund; (c) an election to borrow money against a 401(k) plan account if the loan will result in a liquidation of some or all of a Company stock fund balance; and (d) an election to pre-pay a plan loan if the pre-payment will result in allocation of loan proceeds to the Company stock fund.

Gifts

Bona fide gifts are permissible, subject to the Pre-Clearance requirements of this Policy. Gifts are prohibited in circumstances where the grantor making the gift has reason to believe that the recipient intends to sell the Company Stock while the grantor is aware of MNPI, or the grantor is aware that the recipient intends to sell the Company Stock during a Blackout Period or Non- Trading Window.

Mutual Funds

Transactions in mutual funds invested in Company Stock are not subject to this Policy.

COMPANY TRADING

The Company must comply with U.S. securities laws applicable to its own trading activities, and it will not effect transactions in respect of Company Stock, or adopt any repurchase plans with respect to Company Stock, when it is in possession of MNPI, other than in compliance with applicable law.

ADMINISTRATION, INQUIRIES

The General Counsel shall serve as the compliance officer for this Policy and is responsible for addressing any questions or inquiries. All determinations and interpretations by the General Counsel shall be final and not subject to further review.

CAUTIONARY WARNINGS

The purchase and sale of securities while aware of material nonpublic information, or the disclosure of material nonpublic information to others who then trade in the security, is prohibited by state and federal law. These requirements apply not just to the entity issuing a security but also to the individuals involved in a transaction.

Except as specifically noted herein, there are no exceptions to this Policy. Transactions that may seem necessary, logical or justifiable for independent reasons (such as the need to raise money for an emergency expenditure), or small transactions, are not excepted from this Policy. The securities laws do not recognize any mitigating circumstances, and, in any event, even the appearance of an improper transaction should be avoided to avoid a possible violation of the Company's Code of Conduct or Reg FD Policy.

In all cases, the consequences for trading while in possession of MNPI rest with that individual, and any action on the part of the Company or any other Employee pursuant to this Policy, or otherwise, does not in any way constitute legal advice to an individual or insulate such individual from liability under applicable securities laws.

Every Employee is responsible for their conduct, the Company will not provide a defense or indemnity for any violations or investigations related to individual conduct.

Insider trading violations are pursued vigorously by the SEC, U.S. Attorneys and state enforcement authorities as well as the laws of foreign jurisdictions. Violations can be severe and include surrender of profits as well as civil penalties and imprisonment.

Violations of this Policy must be immediately reported to the General Counsel and may result in disciplinary action up to and including termination.

DEFINITIONS

Blackout Period

The period beginning on the 15th calendar day of the last month of the then current fiscal quarter and ending two (2) business days following the date of the Public Disclosure of the Company's earnings results for that quarter.

Confidential Information

Any Company information that is Confidential as set forth in the Company Code of Conduct. Confidential Information includes MNPI.

Controlled Entity

Any entity that an Employee controls, including any corporations, partnerships or trusts, except those for which the Employee has provided the Company with written notice expressly disclaiming beneficial ownership.

Employee

Everyone included as defined in the Scope.

Family Member

Any relative that resides with an Employee (including a spouse, a child, a child away at college, stepchildren, grandchildren, parents, stepparents, grandparents, siblings and in-laws), anyone else who lives in the same household with an Employee, and any family members who do not live in the household with an Employee but whose transactions in Company Stock are directed by the Employee or are subject to the Employee's influence or control, such as parents or children who consult with the Employee before they trade in Company Stock.

Material Information

Information for which there is a substantial likelihood that a reasonable investor would consider important in deciding to buy, sell or hold a security or could reasonably be expected to have an effect on the price of the Company's Stock. Both positive and negative information may be material. Material information includes, but is not limited to:

- Financial information, such as revenue and earnings, including whether the Company will meet guidance or expectations,
- Mergers, acquisitions, tender offers, joint ventures or changes in assets,
- Developments regarding projects or operations,
- Changes in senior management,
- Financings and other events regarding the Company's Stock,
- Significant litigation, and
- Bankruptcy, restructuring or receivership.

Material Nonpublic Information (MNPI)
Means information that is both Material Information and Nonpublic Information.

Nonpublic Information
Information that has not been previously disclosed to the general public by means of a media release, SEC filing or other means for broad public access.

Non-Trading Window
Any time period involving an event that is material to the Company and is known by a limited number of Employees. So long as the event remains material and nonpublic, any Employee designated by the General Counsel may not trade Company Stock. The existence of an event-specific trading restriction period or extension of a Blackout Period will not be announced to the Company as a whole and should not be communicated to any other Employee.

Pre-Clearance
Approval by the General Counsel or the General Counsel's designee to enter into a Transaction involving any Company Stock.

Public Disclosure
Dissemination of information by: (1) filing a Form 8-K with the SEC, or (2) another method, approved by the General Counsel for a specific communication, that is reasonably designed to provide broad, non-exclusionary distribution of the information to the public.

Securities, (Stock)
Include common and preferred stock, options to purchase stock, or other instruments that may be issued by an entity including, but not limited to, bonds, debentures, and warrants as well as derivative securities that are not issued directly by an entity such as exchange traded put or call options or swaps.

Transaction
Any exchange for value involving Stock.

CERTIFICATION

All Employees subject to this Policy must certify their understanding of, and intent to comply with, this Policy.

Certification

I certify that:

- I have read and understand the Company's Insider Trading Policy (the "Policy"). I understand that the General Counsel is available to answer any questions I have regarding the Policy.
- Since I have been an employee of the Company, I have complied with the Policy.
- I will continue to comply with the Policy for as long as I am subject to the Policy.

Print name: ____ Signature: ____ Date: ____

MURPHY OIL CORPORATION
SUBSIDIARIES OF THE REGISTRANT AS OF DECEMBER 31, 2024

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.2.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. Murphy Building Corporation	Delaware	100.00
2. Murphy Exploration & Production Company - International	Delaware	100.00
a. Canam Offshore LLC	Delaware	100.00
(1) Canam Offshore Limited	Bahamas	100.00
a. Canam Brunei Oil Ltd.	Bahamas	100.00
b. Murphy Peninsular Malaysia Oil Co., Ltd.	Bahamas	100.00
c. 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
d. Murphy Brasil Exploracao e Producao de Petroleo e Gas Ltda. (see company j.(1) below)	Brazil	90.00
e. Murphy Cuu Long Bac Oil Co., Ltd.	Bahamas	100.00
f. Murphy Dai Nam Oil Co., Ltd.	Bahamas	100.00
g. Murphy Equatorial Guinea Oil Co., Ltd.	Bahamas	100.00
h. Murphy Luderitz Oil Co., Ltd.	Bahamas	100.00
i. Murphy Nha Trang Oil Co., Ltd.	Bahamas	100.00
j. Murphy Overseas Ventures Inc.	Delaware	100.00
(1) Murphy Brasil Exploracao e Producao de Petroleo e Gas Ltda.	Brazil	10.00
k. Murphy Phuong Nam Oil Co., Ltd.	Bahamas	100.00
l. Murphy-Spain Oil Company	Delaware	100.00
m. Murphy West Africa, Ltd.	Bahamas	100.00
n. Murphy Worldwide, Inc.	Delaware	100.00
o. Murphy Offshore Oil Co. Ltd.	Bahamas	100.00
p. Murphy Netherlands Holdings B.V.	Netherlands	100.00
(1) Murphy Sur, S. de R. L. de C.V. (see company p(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
q. Murphy Exploration Holdings, LLC	Delaware	100.00

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
(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
t. Murphy CI-102 Oil Co., Ltd.	Bahamas	100.00
u. Murphy CI-103 Oil Co., Ltd.	Bahamas	100.00
v. Murphy CI-502 Oil Co., Ltd.	Bahamas	100.00
w. Murphy CI-531 Oil Co., Ltd.	Bahamas	100.00
x. Murphy CI-709 Oil Co., Ltd.	Bahamas	100.00
3. Murphy Exploration & Production Company - USA	Delaware	100.00
a. MP Gulf of Mexico, LLC	Delaware	80.00
G. Murphy Oil Company Ltd.	Canada	100.00
1. Murphy Canada Holding ULC	AULC	100.00
2. Murphy Canada, Ltd.	Canada	100.00
H. New Murphy Oil (UK) Corporation	Delaware	100.00
1. Murphy Petroleum Limited	England	100.00
a. Murco Petroleum Limited	England	100.00

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the registration statements (No. 333-282615, 333-256048, and 333-241837) on Form S-8 and in the registration statement (No. 333-282655) on Form S-3 of our reports dated February 27, 2025, with respect to the consolidated financial statements and financial statement Schedule II of Murphy Oil Corporation and the effectiveness of internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 27, 2025

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
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 Nos. 333-282615, 333-256048 and 333-241837) on Form S-8, the Registration Statement (File No. 333-282655) 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, 2024 and dated January 24, 2025 for Murphy Oil Corporation, which appears in the December 31, 2024 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 24, 2025

McDANIEL

Jeffrey Wilson
General Manager - Corporate Reserves
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 Kaybob Duvernay and Greater Tupper Montney Projects located within the Province of British Columbia and Alberta, Canada, effective December 31, 2024 and dated January 23, 2025 in the Murphy Oil Corporation Form 10-K for the year ended December 31, 2024, Registration Statement Form S-8, No. 333-282615, 333-256048 and 333-241837 and Registration Statement Form S-3, No. 333-282655 and in any related prospectus, including any reference to our firm under the heading “Experts” in such prospectus.

McDaniel & Associates Consultants Ltd.

/s/ Jared Wynveen

Jared Wynveen, P. Eng.
Executive Vice President

February 24, 2025
APEGA PERMIT NUMBER: P3145

NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 23.4

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the incorporation by reference in the Registration Statement (File Nos. 333-282615, 333-256048 and 333-241837) on Form S-8 and the Registration Statement (File No. 333-282655) on Form S-3 of Murphy Oil Corporation, as well as to the reference in the December 31, 2024, annual report on Form 10-K of Murphy Oil Corporation, of our reports regarding certain assets in the United States located in federal waters in the Gulf of Mexico, effective December 31, 2024, and dated February 11, 2025, including any reference to our firm under the heading "Experts".

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

Houston, Texas
February 25, 2025

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Eric M. Hambly, 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 27, 2025

/s/ Eric M. Hambly
Eric M. Hambly
Principal Executive Officer

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Thomas J. Mireles, 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 27, 2025

/s/ Thomas J. Mireles
Thomas J. Mireles
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, 2024 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), we, Eric M. Hambly and Thomas J. Mireles, 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 27, 2025

/s/ Eric M. Hambly
Eric M. Hambly
Principal Executive Officer

/s/ Thomas J. Mireles
Thomas J. Mireles
Principal Financial Officer

MURPHY OIL CORPORATION

Estimated

Future Reserves

Attributable to the 100%

Leasehold Interests of the

Murphy Petrobras GOM JV

SEC Parameters

As of

December 31, 2024

/s/ Eric T. Nelson

Eric T. Nelson, P.E.
TBPELS License No. 102286
Executive Vice President

[SEAL]

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

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580

1100 LOUISIANA STREET SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 24, 2025

Jeffrey Wilson
General Manager - Corporate Reserves
Murphy Oil Corporation
9805 Katy Freeway, Suite G-200
Houston, TX 77024

Dear Mr. Wilson:

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, 2024 prepared by Murphy's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on January 10, 2025 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, 2024. Based on the estimates of total net proved reserves prepared by Murphy, the reserves audit conducted by Ryder Scott in this report addresses 11.1 percent of the total proved net reserves of Murphy on a barrel of oil equivalent, BOE basis as of December 31, 2024. At Murphy's request, this report 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, 2024 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, 2024, 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 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 below. The net reserves below represent 100 percent of the Murphy and Petrobras GOM JV (MPGOM) and include the non-controlling interest 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, 2024

	Proved		
	Developed	Undeveloped	Total Proved
Net Reserves to MPGOM			
Oil/Condensate – Mbbl	66,718	6,877	73,595
Plant Products – Mbbl	2,651	288	2,939
Gas – MMcf*	21,825	4,367	26,192
MBOE	73,007	7,892	80,899

**Includes fuel gas.*

SEC PARAMETERS
Estimated Net Reserves
Attributable to Murphy’s Leasehold Interests in the
Murphy Petrobras GOM JV (MPGOM)
As of December 31, 2024

	Proved		
	Developed	Undeveloped	Total Proved
Net Reserves to MPGOM			
Oil/Condensate – Mbbl	53,559	5,584	59,143
Plant Products – Mbbl	2,134	233	2,367
Gas – MMcf*	17,692	3,547	21,239
MBOE	58,641	6,407	65,048

**Includes fuel gas.*

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 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 4,474 MMcf at Murphy's leasehold interests of MPGOM, or 1.1 percent of Murphy's 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 primarily 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 categories, 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 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 November 2024, 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 reserves prepared by Murphy attributable to the non-producing and the undeveloped status categories that we reviewed were estimated by performance methods, analogy, 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 2024. 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 producible 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.

The initial SEC hydrocarbon benchmark prices in effect on December 31, 2024 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 following table 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 that 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 following table 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
North America				
United States – Offshore	Oil/Condensate	WTI Cushing	$75.48/Bbl	$75.76/Bbl
	NGLs	WTI Cushing	$75.48/Bbl	$20.04/Bbl
	Gas	Henry Hub	$2.13/MMBTU	$2.44/Mcf

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 for properties where certain abandonment costs were provided by Murphy. Murphy's estimates of the net abandonment costs were accepted without independent verification. We have made no inspections to determine if any additional abandonment, decommissioning, and /or restoration costs may be necessary in addition to the costs provided by Murphy and included herein.

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, 2024. 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, 2024, 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, 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, 2024 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 receive 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 analyses 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.

Murphy Oil Corporation makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Murphy Oil Corporation has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 (File No. 333-260287) and Form S-8 (File Nos. 333-256048 and 333-241837) of Murphy Oil Corporation of the references to our name, as well as to the references to our report for Murphy Oil Corporation, which appears in the December 31, 2024 annual report on Form 10-K of Murphy Oil Corporation. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Murphy Oil Corporation.

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

Executive Vice President

[SEAL]

ETN (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Eric T. Nelson is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Nelson, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2005, is an Executive 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 2024 continuing education hours, Mr. Nelson attended over 20 hours of training during 2024 covering such topics as CCUS, 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 19 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 23, 2025

Murphy Oil Corporation
9805 Katy Freeway
Suite G-200
Houston, Texas
USA 77024

Attention: Mr. Jeffrey Wilson, General Manager – Corporate Reserves

Reference: **Murphy Oil Corporation**
Evaluation of the Canadian Oil and Gas Properties as of December 31, 2024

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 Kaybob Duvernay and Greater Tupper Montney Projects located within the Province of British Columbia and Alberta, Canada. Murphy holds a 99.94 percent working interest in the Greater Tupper Montney Project, a 70.00 percent working interest in the Kaybob Duvernay Project. Murphy has represented that these properties account for approximately 52.9 percent of its total company proved reserves on an equivalent barrel basis as of December 31, 2024, 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, 2024, for the same properties as those which we audited. The completion date of our report is January 23, 2025. 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, 2024. 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 2024 first-of-the month fiscal average pricing using benchmark pricing supplied by Murphy. Oil prices were based upon West Texas Intermediate at Cushing crude oil benchmark of USD$75.48 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$1.96 per Mcf of natural gas including fuel volumes (CAD$1.98 per Mcf excluding fuel volumes) and CAD$92.22 per barrel of natural gas liquids. For total proved reserves in the Kaybob Duvernay Project, the estimated realized prices were CAD$1.46 per Mcf of natural gas, CAD$93.88 per barrel of oil and CAD$43.51 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.

Murphy Estimates

Murphy has represented that estimated proved reserves attributable to the audited properties are based on SEC definitions. 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, 2024
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				
Kaybob Duvernay	6,162	3,562	1,484	11,208
Tupper Montney	—	188,637	726	189,363
Proved Undeveloped				
Kaybob Duvernay	10,752	4,329	1,869	16,950
Tupper Montney	—	167,789	454	168,243
Total Proved				
Kaybob Duvernay	16,914	7,891	3,353	28,158
Tupper Montney	—	356,426	1,180	357,606

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, 3,672 Mboe are attributed to fuel gas reserves in the Kaybob Duvernay and 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, 932-235-50-9, 932-235-50-30 and 932-235-50-31 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 Wynveen, P.Eng., Executive Vice President has been with the firm since 2006, and has over 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's properties. Mr. Wynveen is a registered professionals with the Association of Professional Engineers and Geoscientist of Alberta (APEGA) with over 15 years of experience with the firm.

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

/s/ Jared Wynveen

Jared Wynveen, P.Eng.
Executive Vice President
January 23, 2025

JW:jep
[24-0160]

CERTIFICATE OF QUALIFICATION

I, Jared W. B. Wynveen, Petroleum Engineer of 2000, 525 - 8th Avenue SW, 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 the Canadian Oil and Gas Properties, As of December 31, 2024", dated January 23, 2025, 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 23, 2025

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

February 11, 2025

Mr. Jeffrey Wilson
Murphy Exploration & Production Company
9805 Katy Freeway, Suite G-200
Houston, Texas 77024
Dear Mr. Wilson:

In accordance with your request, we have audited the estimates prepared by Murphy Exploration & Production Company (Murphy E&P), as of December 31, 2024, of the proved reserves to the Murphy E&P interest in certain oil and gas properties located in federal waters in the Gulf of Mexico. The scope of our work did not include auditing the future net revenue associated with these reserves. It is our understanding that Murphy E&P is a wholly owned subsidiary of Murphy Oil Corporation (Murphy Oil) and that the proved reserves estimates shown herein constitute approximately 8 percent of all proved reserves owned by Murphy Oil. Economic analysis was performed by Murphy E&P only to confirm economic producibility and determine economic limits for the properties. We have examined the estimates with respect to reserves quantities, reserves categorization, future producing rates, and economic producibility, using the definitions set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Rule 4-10(a). The estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—*Oil and Gas*. We completed our audit on January 8, 2025. This report has been prepared for Murphy Oil's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The following table sets forth Murphy E&P's estimates of the net reserves, as of December 31, 2024, for the audited properties:

	Net Reserves			
Category	Oil (MBBL)	NGL (MBBL)	Gas[(1)] (MMCF)	Oil Equivalent (MBOE)
Proved Developed	27,145	3,991	44,400	38,537
Proved Undeveloped	10,653	2,428	20,719	16,535
Total Proved	37,798	6,420	65,119	55,071

Totals may not add because of rounding.

(1) Gas reserves are inclusive of fuel gas volumes expected to be consumed in field operations; fuel gas volumes are approximately 1 percent of the total proved reserves.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Oil equivalent volumes are expressed in thousands of barrels of oil equivalent (MBOE), determined using the ratio of 6 MCF of gas to 1 barrel of oil.

When compared on a field-by-field basis, some of the estimates of Murphy E&P are greater and some are less than the estimates of Netherland, Sewell & Associates, Inc. (NSAI). However, in our opinion the estimates shown herein of Murphy E&P's reserves are reasonable when aggregated at the proved level and have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). Additionally, these estimates are within the recommended 10 percent tolerance threshold set forth in the SPE Standards. We are satisfied with the methods and procedures used by Murphy E&P in preparing the December 31, 2024, estimates of reserves, and we saw nothing of an unusual nature that would cause us to take exception with the estimates, in the aggregate, as prepared by Murphy E&P.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves included herein have not been adjusted for risk. Murphy E&P 's estimates do not include probable or possible reserves that may exist for these properties.

Oil, NGL, and gas prices were used only to confirm economic producibility and determine economic limits for the properties. Prices used by Murphy E&P are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2024. For oil and NGL volumes, the average NYMEX West Texas Intermediate spot price of $75.48 per barrel is adjusted by field for quality and market differentials. For gas volumes, the average Henry Hub spot price of $2.13 per MMBTU is adjusted by field for energy content and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $76.05 per barrel of oil, $16.95 per barrel of NGL, and $2.32 per MCF of gas.

Costs were used only to confirm economic producibility and determine economic limits for the properties. Operating costs used by Murphy E&P are based on historical operating expense records. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Murphy E&P are included to the extent that they are covered under joint operating agreements for the operated properties. Capital costs used by Murphy E&P are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Abandonment costs used are Murphy E&P's estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. Operating, capital, and abandonment costs are not escalated for inflation.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, estimates of Murphy E&P and NSAI are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Murphy E&P, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts used to confirm economic producibility and determine economic limits for the properties. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing these estimates.

It should be understood that our audit does not constitute a complete reserves study of the audited oil and gas properties. Our audit consisted primarily of substantive testing, wherein we conducted a detailed review of all properties. In the conduct of our audit, we have not independently verified the accuracy and completeness of information and data furnished by Murphy E&P with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of our examination something came to our attention that brought into question the validity or sufficiency of any 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. Our audit did not include a review of Murphy E&P's overall reserves management processes and practices.

We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to establish the conclusions set forth herein. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Supporting data documenting this audit, along with data provided by Murphy E&P and Murphy Oil, are on file in our office. The technical persons primarily responsible for conducting this audit meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. John R. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Zachary R. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ Richard B. Talley, Jr.
By:
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

/s/ John R. Cliver /s/ Zachary R. Long
By: By:
John R. Cliver, P.E. 107216 Zachary R. Long, P.G. 11792
Senior Vice President Vice President

Date Signed: February 11, 2025 Date Signed: February 11, 2025

JRC:RS