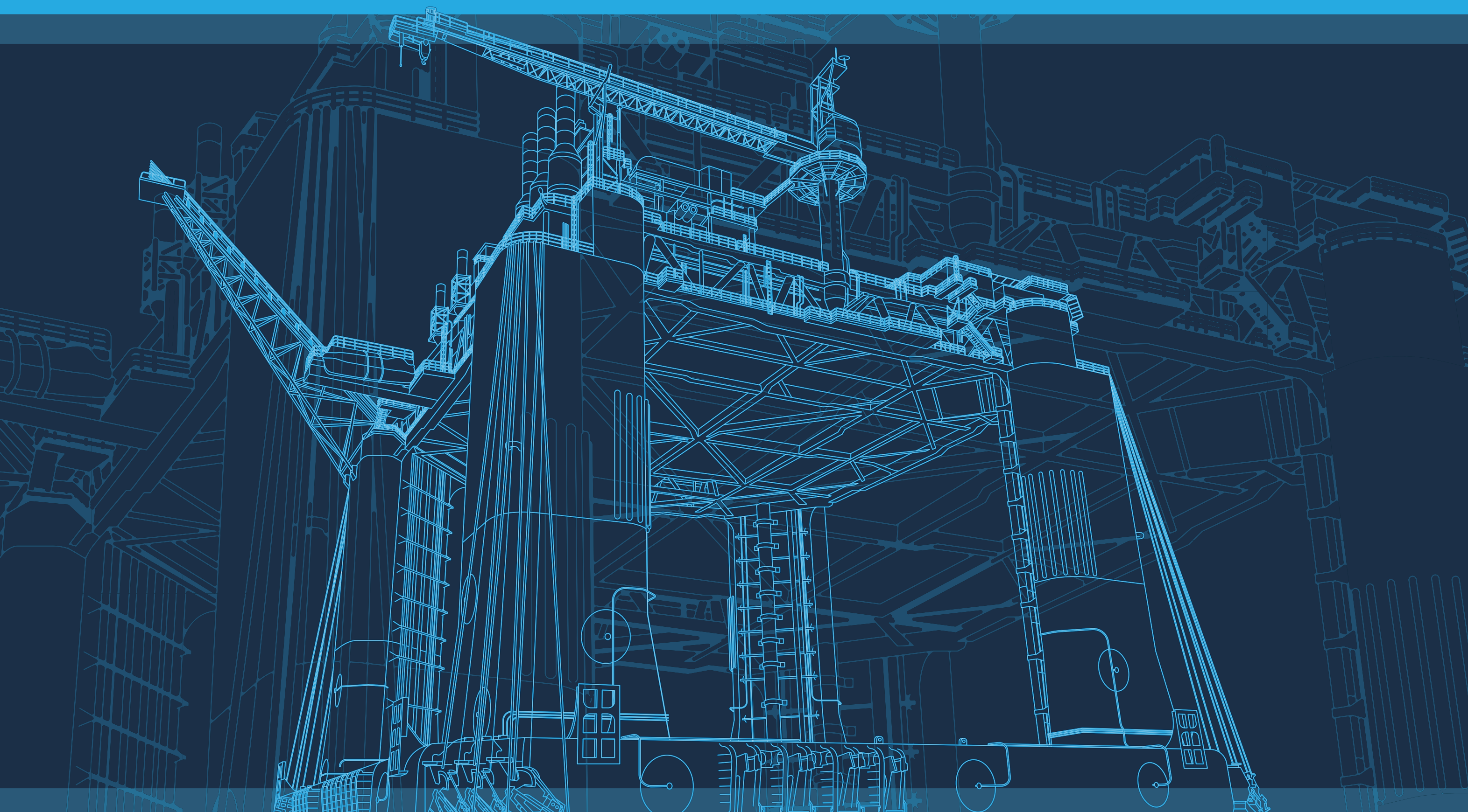
MURPHY OIL CORPORATION

2022 ANNUAL REPORT



ENERGY THAT EMPOWERS PEOPLE

do right always | think beyond possible | stay with it

MURPHY
OIL CORPORATION

Roger W. Jenkins
President and Chief Executive Officer

DEAR FELLOW SHAREHOLDER

Murphy had an outstanding year in 2022. We advanced our strategy of Delever, Execute, Explore, and added the priority of Return as we look to further enhance payouts to our shareholders through dividend increases, reaching the current level of $1.10 per share on an annualized basis. While working to advance these four key priorities, we also remained focused on ensuring Murphy's long-term sustainability within the energy transition.

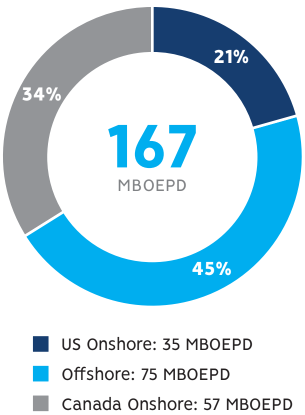
Murphy's ongoing sustainability efforts achieved excellent metrics in 2022, as we lowered emissions intensity five percent from 2021, as well as reduced our onshore flared volumes — both to the lowest level on company record. We have now achieved a second consecutive year of no recordable spills. Additionally, the team's efforts enabled us to recycle three million barrels of water, or 28 percent of total water use across our North America onshore assets.

Delever
Murphy successfully achieved its $650 million debt reduction goal in 2022, thereby accomplishing 40 percent, or $1.2 billion, of total debt reduction since year-end 2020, and reaching its lowest debt level in more than a decade. Further, we held significant cash and cash equivalents of nearly $500 million at year-end 2022. Also, during the year, the company preserved its long-term liquidity by entering into a new $800 million senior unsecured credit facility, which was undrawn at year-end 2022.

For 2023, we are targeting $500 million of additional debt reduction, assuming $75 per barrel oil price. Upon completion of that goal, we forecast $1.3 billion of total debt at year-end.

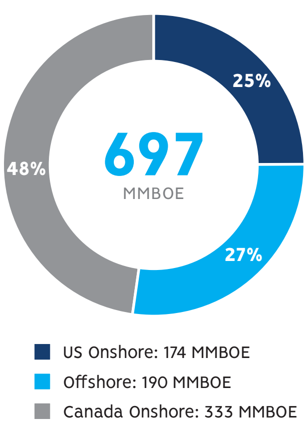
(continued overleaf)

2022 Production by Area



"Our focused execution throughout the year led to a 29 percent increase in oil volumes from first quarter to fourth quarter 2022, primarily driven by completing the Khaleesi, Mormont, Samurai field development project."

2022 Proved Reserves by Area



Execute

Our consistent emphasis on execution resulted in $2.2 billion of net cash provided by continuing operations, including noncontrolling interest. This is a level not seen since 2014. Additionally, we generated approximately $1.3 billion of free cash flow[1], which enabled us to accomplish our delevering goals for the year. Specifically, Murphy produced 167 thousand barrels of oil equivalent per day — the highest level since 2019 — with 90 thousand barrels of oil per day in 2022.

Our focused execution throughout the year led to a 29 percent increase in oil volumes from first quarter to fourth quarter 2022, primarily driven by completing the Khaleesi, Mormont, Samurai field development project in the Gulf of Mexico, with seven wells brought online and all three fields producing above expectations.

This milestone project has been a significant feat from start to finish and reflects our competitive advantage in offshore execution capability, from building the Murphy-operated King's Quay floating production system overseas during COVID-19, to transporting it across the globe and achieving first oil in the Gulf of Mexico ahead of schedule. Since volumes began producing from the three fields, King's Quay has realized an industry-leading 97 percent uptime.

Our onshore well delivery program brought 50 operated wells online, with our revised completions method resulting in some of the highest per-foot initial production rates in company history. In the Eagle Ford Shale, these results translated into realizing full investment recovery in less than a year, while our Tupper Montney wells were forecast to average full investment recovery in less than six months. Additionally, the team targeted all aspects of the drilling, completion and production process as they managed base production declines and well optimization. For the year, Murphy achieved industry-leading well results, which was validated in a recent sell-side report on the Eagle Ford Shale.

Overall, we achieved total reserve replacement of 98 percent for 2022, with 697 million barrels of oil equivalent in proved reserves at year-end and a reserve life of more than 11 years. For 2022, our proved developed reserves increased slightly to 60 percent of the total, while the liquids-weighting rose to 47 percent.

Explore

In addition to holding a large base of proved reserves, Murphy maintains a sizeable portfolio of exploration prospects across the Gulf of Mexico, offshore Mexico, Brazil and Vietnam.

We drilled a successful well at Samurai #5 after previously discovering additional pay zones in the Samurai field during the initial phase of development. The Samurai field was initially discovered by Murphy's exploration team, and this additional well allows us to build on the success of the field as it is one of the most promising economic opportunities I have seen in my career.

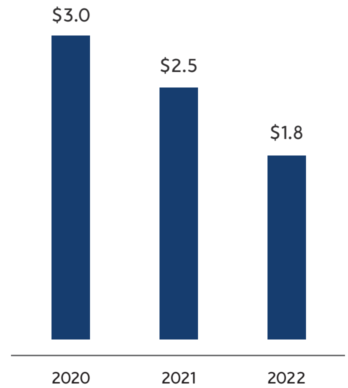
For 2023, we look forward to running an operated exploration campaign in the Gulf of Mexico with three wells.

Return

As we advanced our delevering efforts in 2022, Murphy became increasingly determined to support our longstanding shareholders, and added Return as the fourth pillar of our strategy. We enhanced our returns through doubling the dividend to $1.00 per share on an annualized basis, with a recent increase in 2023 to $1.10 per share annualized, representing the highest planned annualized rate since 2016. In promotion of this strategy, we announced the capital allocation framework in mid-2022, which established increasing shareholder returns tied to targeted debt reduction goals.

At year-end, our total debt level of $1.8 billion positioned us to begin Murphy 2.0 in 2023, enabling us to allocate 25 percent of adjusted free cash flow[2] to shareholders through share buybacks and potential dividend increases, with 75 percent allocated to further debt reduction. Once we reach a total debt level of $1.0 billion, we will advance into Murphy 3.0, where the allocation changes: directing 50 percent to shareholders and 50 percent to the balance sheet.

Total Debt Outstanding
$ Billion



Making It Better

As disclosed in our 2022 Sustainability Report, Murphy was selected to participate in an environmental, social and governance (ESG) pilot program with our third-party contractor and supplier information management provider. This program is aimed at the assessment and documentation of ESG performance by Murphy and its contractor companies, including verification of certain data, and will enable us to provide further transparency on our ESG practices as we work to achieve our goals. Also in 2022, we published a Supplier Code of Conduct to better ensure alignment between Murphy and its suppliers, as well as our fourth annual Sustainability Report, which included expanded disclosures and metrics.

"Effective in 2022, three board committees enhanced their charters to reflect continued oversight of ESG-related responsibilities."

At the board level, effective in 2022, three board committees enhanced their charters to reflect continued oversight of ESG-related responsibilities. Additionally, the Compensation Committee incorporated a greenhouse gas emissions intensity performance metric to accompany the safety and spill rate metrics included in the ESG component of Murphy's Annual Incentive Plan.

Remaining Committed

I appreciate our talented employees for all their hard work this past year. We could not have achieved our goals without their enduring attention on leaning into the challenges, particularly in accomplishing our major projects and production improvements. I would also like to thank our Board of Directors for their ongoing leadership as we continue to think beyond possible as an energy leader. We would like to extend a special thank you to Steve Cossé, Jay Collins and Neal Schmale, who will be retiring from the board in May. They have provided incredible input on a multitude of committees during their tenure, having joined in 2011, 2013 and 2004, respectively. On behalf of the Board of Directors and employees, we wish them all the best. Lastly, thank you to our longstanding stockholders for remaining supportive of Murphy Oil Corporation as we look to the future.

Roger W. Jenkins
President and Chief Executive Officer

Note: Unless otherwise noted, the production, reserves and financial metrics discussed in this Shareholder Letter and accompanying information exclude the noncontrolling interest in MP Gulf of Mexico, LLC (MP GOM), thereby representing only the amounts attributable to Murphy. Proved reserves are based on year-end 2022 third-party audited volumes using SEC pricing.

[1] Free cash flow is calculated as net cash provided by continuing operations activities (which includes noncontrolling interest) and before noncash working capital changes, less property additions and dry hole costs

[2] Adjusted free cash flow is calculated as net cash provided by continuing operations activities before noncash working capital changes, less property additions and dry hole costs, acquisition of oil and natural gas properties, cash dividends paid, distributions to noncontrolling interest and other contractual payments

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, 2022

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 30, 2022) – $3,017,884,510.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2023 was 155,762,646.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 10, 2023 have been incorporated by reference in Part III herein.

MURPHY OIL CORPORATION
2022 FORM 10-K
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PART I

Item 1. BUSINESS

Summary

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

The Company was originally incorporated in Louisiana in 1950 as Murphy Corporation. It was reincorporated in Delaware in 1964, at which time it adopted the name Murphy Oil Corporation and was reorganized in 1983 to operate primarily as a holding company of its various businesses. In 2013, the U.S. downstream business was separated from Murphy Oil Corporation's oil and natural gas exploration and production business. For reporting purposes, Murphy's exploration and production activities are subdivided into three geographic segments, including the United States, Canada and all other countries. Additionally, 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 following relocation from El Dorado, Arkansas in 2020.

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 10.

In addition to the following information about each business activity, data about Murphy's operations, properties and business segments, including revenues by class of products and financial information by geographic area, are provided on pages 32 through 47, 80 through 81, 104 through 106, 110 through 125 and 127 of this Form 10-K report.

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

Exploration and Production

The Company produces crude oil, natural gas and natural gas liquids primarily in the U.S. and Canada and explores for crude oil, natural gas and natural gas liquids in targeted areas worldwide.

During 2022, Murphy's principal exploration and production activities were conducted in the United States by wholly-owned Murphy Exploration & Production Company – USA (Murphy Expro USA) and its subsidiaries, in Canada by wholly-owned Murphy Oil Company Ltd. (MOCL) and its subsidiaries and in Australia, Brazil, Brunei, Mexico and Vietnam by wholly-owned Murphy Exploration & Production Company – International (Murphy Expro International) and its subsidiaries. Murphy's operations and production in 2022 were in the United States, Canada and Brunei. Murphy is in the process of winding down operations in Australia.

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

Murphy's worldwide 2022 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 175,156 barrels of oil equivalent per day, an increase of 4.7% compared to 2021.

For further details on business execution, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" starting on page 32. For further details on 2022 production and sales volume see pages 40 to 43.

United States

In the United States, Murphy produces crude oil, natural gas liquids and natural gas primarily from fields in the Gulf of Mexico and in the Eagle Ford Shale area of South Texas. The Company produced approximately 99,626 barrels of crude oil and natural gas liquids per day and approximately 92 MMCF of natural gas per day in the

U.S. in 2022. These amounts represented 92.2% of the Company's total worldwide oil and natural gas liquids and 23.0% of worldwide natural gas production volumes.

Offshore

The Company holds rights to approximately 620 thousand gross acres in the Gulf of Mexico. During 2022, approximately 70% of total U.S. hydrocarbon production was produced at fields in the Gulf of Mexico, of which approximately 79% was derived from nine fields, including Khaleesi, Mormont, Cascade, Chinook, Neidermeyer, Dalmatian, St. Malo, Kodiak and Lucius. Total average daily production in the Gulf of Mexico in 2022 was 70,008 barrels of crude oil and natural gas liquids and 63 MMCF of natural gas. At December 31, 2022, Murphy had total proved reserves for Gulf of Mexico fields of 162.3 million barrels of oil and natural gas liquids and 124.9 billion cubic feet of natural gas.

The Company has various operated and non-operated fields in the U.S. Gulf of Mexico. The most significant fields are St. Malo, Khaleesi, Mormont, Samurai, Lucius and Dalmatian. The Khaleesi Mormont Samurai development project achieved first oil in 2022 and completed the initial seven well program.

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 2022, approximately 30% of total U.S. hydrocarbon production was produced in the Eagle Ford Shale. Total 2022 production in the Eagle Ford Shale area was 29,556 barrels of oil and liquids per day and 28.8 MMCF per day of natural gas. At December 31, 2022, the Company's proved reserves for the U.S. onshore business totaled 138.9 million barrels of liquids and 210 billion cubic feet of natural gas.

<u>Canada</u>

In Canada, the Company holds working interests in Tupper Montney (100% owned), Kaybob Duvernay (operated), Placid Montney (non-operated) and two non-operated offshore assets – the Hibernia and Terra Nova fields, located offshore Newfoundland in the Jeanne d'Arc Basin.

Onshore

Murphy has approximately 142 thousand gross acres of Tupper Montney mineral rights located in northeast British Columbia. In addition, the Company holds a 70% operated working interest in Kaybob Duvernay lands and a 30% non-operated working interest in liquids rich Placid Montney lands, both in Alberta. The Company has approximately 289 thousand gross acres of Kaybob Duvernay and Placid Montney mineral rights. Daily production in 2022 in onshore Canada averaged 4,908 barrels of liquids and 310 MMCF of natural gas. Total onshore Canada proved liquids and natural gas reserves at December 31, 2022, were approximately 21.4 million barrels and 1.9 trillion cubic feet, respectively.

The Company currently has a commitment for 483 million cubic feet per day (MMCFD) of natural gas processing capacity to support production in the Tupper Montney through April 2036, with the commitment reducing to 198 MMCFD for the remainder of the period until November 2040.

Offshore

The Company has an interest in approximately 129 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% working interest at Terra Nova.

Oil production in 2022 was 2,812 barrels of oil per day for Hibernia.

During 2022, Terra Nova did not produce as an asset life extension project was being undertaken. Production is expected to resume in the first half of 2023, with estimated asset life extended to 2032.

Total proved reserves for offshore Canada at December 31, 2022 were approximately 22.2 million barrels of liquids and 15.1 billion cubic feet of natural gas.

Australia

In Australia, the Company has interest in approximately 482 thousand gross acres and holds one offshore exploration permit; Murphy is not the operator. The permit does not have a drilling commitment.

Brazil

The Company holds an interest in nine blocks in the offshore regions of the Sergipe-Alagoas Basin (SEAL) in Brazil (SEAL-M-351, SEAL-M-428, SEAL-M-430, SEAL-M-501, SEAL-M-503, SEAM-M-505, SEAL-M-573, SEAL-M-575 and SEAL-M-637). ExxonMobil is the operator of the blocks. Murphy has a 20% working interest, ExxonMobil has a 50% working interest and Enauta Energia SA holds a 30% working interest.

Murphy has also farmed into 3 additional blocks in the Potiguar Basin (POT-M-857, POT-M-863 and POT-M-865) with a 30% working interest; in 2022, Murphy transitioned to operator at 100% working interest when Wintershall Dea, the former operator, announced that it would terminate all operations in Brazil.

Murphy's total acreage position in Brazil as of December 31, 2022 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, 2022. During 2022 the Company sold its 30% working interest in Block CA-2 which was previously classified as held for sale.

Oil production in 2022 was 700 barrels of oil per day for Brunei.

Total proved reserves for our Jagus East discovery in Block CA-1 at December 31, 2022 were approximately 0.5 million barrels of liquids and 0.2 billion cubic feet of natural gas. Block CA-1 covers 1.4 million gross acres.

Mexico

In March 2017, as part of Mexico's fourth phase, round one deepwater auction, Murphy was awarded Block 5. Murphy is the operator of the block with a 40% working interest. Block 5 is located in the deepwater Salinas Basin covering approximately 640 thousand gross acres (2,600 square kilometers), with water depths ranging from 2,300 to 3,500 feet (700 to 1,100 meters). The initial exploration period for the license is four years and includes a commitment to drill one exploration well which was drilled in 2019. A further exploration well was drilled in 2022 which did not find commercial hydrocarbons.

Vietnam

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

Block 15-1/05 contains the Lac Da Vang (LDV) discovered field and the consortium are awaiting final approval of the development plan. Declaration of Commerciality was made in January 2019 and the field Outline Development Plan was approved in August 2019. The Lac Da Trang (LDT) 1X exploration well, the last remaining commitment of the PSC, was completed in April 2019. The Field Development Plan of the LDV development was adopted by PetroVietnam and being progressed for final approval by the Government.

In Block 15-2/17, the Company is progressing study activity in anticipation of drilling an exploration commitment well by 2024.

In blocks 144 and 145, the Company acquired 2D seismic for these blocks in 2013 and undertook seabed surveys in 2015 and 2016. The remaining commitment for the acquisition, processing and interpretation of eight hundred square kilometers of 3D seismic is tentatively scheduled for 2024. In addition, the Company will be seeking to extend the exploration period.

Proved Reserves

Total proved reserves for crude oil, natural gas liquids and natural gas as of December 31, 2022 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	**264.2**	**194.4**	**27.4**	**254.1**
Onshore	121.8	76.6	19.1	156.6
Offshore [1]	142.4	117.8	8.3	97.5
Canada	**171.3**	**14.2**	**2.3**	**928.8**
Onshore	165.0	8.6	2.3	924.8
Offshore	6.3	5.6	–	4.0
Other	**0.5**	**0.4**	**–**	**0.2**
Total proved developed reserves	**436.0**	**209.0**	**29.7**	**1,183.1**
Proved Undeveloped Reserves:				
United States	**92.8**	**69.2**	**10.2**	**80.8**
Onshore	52.0	35.5	7.7	53.4
Offshore [2]	40.8	33.7	2.5	27.4
Canada	**186.5**	**25.3**	**1.8**	**956.0**
Onshore	168.0	8.7	1.8	944.9
Offshore	18.5	16.6	–	11.1
Other	**0.1**	**0.1**	**–**	**–**
Total proved undeveloped reserves	**279.4**	**94.6**	**12.0**	**1,036.8**
Total proved reserves [3]	**715.4**	**303.6**	**41.7**	**2,219.9**

[1] Includes proved developed reserves of 15 MMBOE, consisting of 13.7 million barrels of oil (MMBBL) oil, 0.5 MMBBL NGLs and 4.2 BCF natural gas, attributable to the noncontrolling interest in MP GOM.

[2] Includes proved undeveloped reserves of 3.2 MMBOE, consisting of 2.8 MMBBL oil, 0.1 MMBBL NGLs and 1.4 BCF natural gas, attributable to the noncontrolling interest in MP GOM.

[3] Includes proved reserves of 18.2 MMBOE, consisting of 16.5 MMBBL oil, 0.6 MMBBL NGLs and 5.6 BCF natural gas, attributable to the noncontrolling interest in MP GOM.

[4] Includes proved natural gas reserves to be consumed in operations as fuel of 74.9 BCF and 43.5 BCF for the U.S. and Canada, respectively, with 0.8 BCF attributable to the noncontrolling interest in MP GOM.

Murphy Oil's 2022 total proved reserves and proved undeveloped reserves are reconciled from 2021 as presented in the table below:

(Millions of oil equivalent barrels) [1]	Total Proved Reserves	Total Proved Undeveloped Reserves
Beginning of year	716.9	297.7
Revisions of previous estimates	(23.6)	(8.1)
Extensions and discoveries	80.1	79.4
Improved recovery	5.3	5.3
Conversions to proved developed reserves	–	(96.9)
Purchases of properties	5.0	2.0
Sale of properties	(4.4)	–
Production	(63.9)	–
End of year [2]	**715.4**	**279.4**

[1] For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of oil using a ratio of six MCF of natural gas to one barrel of oil.
[2] Includes 18.2 MMBOE and 3.2 MMBOE for total proved and proved undeveloped reserves, respectively, attributable to the noncontrolling interest in MP GOM.

During 2022, Murphy's total proved reserves decreased by 1.5 million barrels of oil equivalent (MMBOE). The decrease in reserves principally relates to production of 63.9 MMBOE in 2022 and negative price revisions in Tupper Montney from higher commodity prices resulting in increased royalty rates and accelerated royalty incentive payouts. These revisions were offset by extensions of 58.5 MMBOE in onshore Canada, 15.8 MMBOE in offshore U.S. Gulf of Mexico and offshore Canada, and 5.8 MMBOE in the Eagle Ford Shale; improved recovery in the Gulf of Mexico; as well as acquisitions of increased working interest in two producing fields in the Gulf of Mexico and offsetting dispositions in the Gulf of Mexico and the Eagle Ford Shale.

Murphy's total proved undeveloped reserves at December 31, 2022 decreased 18.3 MMBOE from a year earlier. The proved undeveloped reserves reported in the table as extensions and discoveries during 2022 were predominantly attributable to four areas: the U.S. Gulf of Mexico, the Eagle Ford Shale in South Texas, onshore Canada areas of Tupper Montney and Kaybob Duvernay, and offshore Canada. Each of these areas had active development work ongoing during the year. The majority of proved undeveloped reserves associated with revisions of previous estimates was the result of negative price revisions in Tupper Montney from higher commodity prices resulting in increased royalty rates and accelerated royalty incentive payouts. The majority of the proved undeveloped reserves migration to the proved developed category are attributable to drilling in the Tupper Montney and Kaybob Duvernay, the Gulf of Mexico, and the Eagle Ford Shale. Other proved undeveloped increases resulted from improved recovery as well as an acquisition of increased working interest in two producing fields in the Gulf of Mexico.

The Company spent approximately $770 million in 2022 to convert proved undeveloped reserves to proved developed reserves. In the next three years, the Company expects to spend a range of approximately $350 million to $650 million per year to move current undeveloped proved reserves to the developed category. The anticipated level of spending in 2023 primarily includes drilling and development in the Gulf of Mexico, Eagle Ford Shale and Tupper Montney areas.

At December 31, 2022, proved reserves are included for several development projects, including oil developments at the Eagle Ford Shale in South Texas, deepwater Gulf of Mexico; and Kaybob Duvernay in onshore Canada; as well as natural gas developments at Tupper Montney in onshore Canada. Total proved undeveloped reserves associated with various development projects at December 31, 2022 were approximately 279.4 MMBOE, which represent 39% of the Company's total proved reserves.

Certain development projects have proved undeveloped reserves that will take more than five years to bring to production. The Company currently operates deepwater fields in the Gulf of Mexico that have four undeveloped locations that exceed this five-year window. Total reserves associated with the four locations amount to approximately 1% of the Company's total proved reserves at year-end 2022. 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

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

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

Proved reserves are then consolidated and reported through the Corporate Reserves group. Murphy's General Manager 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 31 years of industry experience. He has a Bachelor of Science in Mechanical Engineering and is a 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 of Directors about the Company's reserves. The Reserves Manager and the Corporate reserve engineers review and discuss reserves estimates directly with the Company's technical staff in order to make every effort to ensure compliance with the rules and regulations of the SEC. The Reserves General Manager coordinates and oversees the third-party audits which are performed annually and under Company policy generally target coverage of at least one-third of the barrel oil-equivalent volume of the Company's proved reserves.

The estimated proved reserves reported in this Form 10-K are prepared by Murphy's employees. Internal audits may also be performed by the Reserves General Manager and qualified engineering staff from areas of the Company other than the area being audited by third parties. In 2022, 98.0% of the Proved reserves were audited by third-party auditors and they were found to be within the acceptable 10.0% tolerance by each of the third-party firms. Murphy engaged both Ryder Scott Company, L.P. and McDaniel & Associates Consultants Ltd. to perform a reserves audit of 49.9% and 48.1% of the Company's total proved reserves, respectively.

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

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

The Company's QREs maintain files containing pertinent data regarding each significant reservoir. Each file includes sufficient data to support the calculations or analogies used to develop the values. Examples of data included in the file, as appropriate, include: production histories; pertinent drilling and workover histories; bottom hole pressure data; volumetric, material balance, analogy, or other pertinent reserve estimation data; production performance curves; narrative descriptions of the methods and logic used to determine reserves values; maps and logs; and a signed copy of the documentation stating that, in their opinion, the reserves have been calculated, reviewed, documented and reported in compliance with SEC regulations. Reserves calculations are completed by technical personnel with the support of the QREs and appropriately reviewed by RRCs, the Corporate reserves engineers and the Reserves General Manager. Summaries are reviewed and approved with the heads of the Company's exploration and production business units and other senior management on an annual basis. The Company's Controller's department is responsible for preparing and filing reserves schedules within the Form 10-K report.

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

More information regarding Murphy's estimated quantities of proved reserves of crude oil, natural gas liquids and natural gas for the last three years are presented by geographic area on pages 112 through 119 of this Form 10-K report. 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 United States to the U.S. Department of Energy; such reserves are derived from the same data from which estimated proved reserves of such properties are determined.

Crude oil, condensate and natural gas liquids production and sales, and natural gas sales by geographic area with weighted average sales prices for each of the three years ended December 31, 2022 are shown on pages 41 through 43 of this Form 10-K report.

Production expenses for the last three years in U.S. dollars per equivalent barrel are discussed beginning on page 38 of this Form 10-K report.

Supplemental disclosures relating to oil and natural gas producing activities are reported on pages 110 through 125 of this Form 10-K report.

Acreage and Well Count

At December 31, 2022, Murphy held leases, concessions, contracts or permits on developed and undeveloped acreage as shown by geographic area in the following table. Gross acres are those in which all or part of the working interest is owned by Murphy. Net acres are the portions of the gross acres attributable to Murphy's interest.

		Developed		Undeveloped		Total	
Area (Thousands of acres)		Gross	Net	Gross	Net	Gross	Net
United States	Onshore	109	96	24	23	133	119
	Gulf of Mexico	60	27	560	271	620	298
Total United States		169	123	584	294	753	417
Canada	Onshore	152	116	279	195	431	311
	Offshore	101	11	28	1	129	12
Total Canada		253	127	307	196	560	323
Mexico		–	–	636	254	636	254
Brazil		–	–	2,453	1,110	2,453	1,110
Australia		–	–	482	241	482	241
Brunei		2	–	1,446	116	1,448	116
Vietnam		–	–	7,324	4,571	7,324	4,571
Spain		–	–	8	1	8	1
Totals		424	250	13,240	6,783	13,664	7,033

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

Scheduled expirations in 2023 include 241 thousand net acres in Australia, 116 thousand net acres in Brunei, 75 thousand net acres in Brazil, 34 thousand net acres in onshore Canada,16 thousand net acres in the Gulf of Mexico, 5 thousand net acres in Mexico and 1 thousand net acres in Spain.

Acreage currently scheduled to expire in 2024 include 4.5 million net acres in Vietnam, 47 thousand net acres in the Gulf of Mexico and 17 thousand net acres in onshore Canada.

Scheduled expirations in 2025 include 249 thousand net acres in Mexico, 37 thousand net acres in Brazil, 7 thousand net acres in the Gulf of Mexico and 5 thousand net acres in onshore Canada.

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

The following table shows the number of oil and natural gas wells producing or capable of producing at December 31, 2022.

		Oil Wells		Natural Gas Wells	
		Gross	Net	Gross	Net
Country					
United States	Onshore	1,139	917	30	4
	Gulf of Mexico	77	34	13	6
Total United States		1,216	951	43	10
Canada	Onshore	18	13	400	338
	Offshore	47	5	–	–
Total Canada		65	18	400	338
Totals		1,281	969	443	348

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
2022								
Exploration	–	–	–	–	–	**0.6**	–	**0.6**
Development	**29.1**	–	**22.1**	–	–	–	**51.2**	–
2021								
Exploration	–	0.1	–	–	–	–	–	0.1
Development	27.9	–	14.6	–	–	–	42.5	–
2020								
Exploration	–	0.4	0.7	–	–	–	0.7	0.4
Development	21.5	–	8.9	–	–	–	30.4	–

Murphy's drilling wells in progress at December 31, 2022 are shown in the following table. The year-end well count includes wells awaiting various completion operations.

		Exploration		Development		Total	
		Gross	Net	Gross	Net	Gross	Net
Country							
United States	Onshore	–	–	15.0	7.0	15.0	7.0
	Gulf of Mexico	1.0	0.3	4.0	1.6	5.0	1.9
Canada	Onshore	–	–	5.0	5.0	5.0	5.0
	Offshore	–	–	–	–	–	–
Totals		1.0	0.3	24.0	13.6	25.0	13.9

Sustainability

Environment and Climate Change

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

We are committed to reducing our GHG emissions and 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. In 2021, we endorsed the goal of eliminating routine flaring by 2030, under the current World Bank definition of routine flaring. This adds to the Company's previously established GHG emissions intensity reduction target of 15% to 20% by 2030 from our 2019 level, excluding our discontinued and divested Malaysia operations.

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

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

U.S. Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). CERCLA and similar state statutes impose joint and several liability, without regard to fault or legality of the conduct, on current and past owners or operators of a site where 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 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 Mexico and also require lessees to have substantial U.S. assets and net worth or post bonds or other acceptable financial assurance that the regulatory obligations will be met.

These include, in the Gulf of Mexico, well design, well control, casing, cementing, real-time monitoring and subsea containment, among other items. Under applicable requirements, BOEM evaluates the financial strength and reliability of lessees and operators active on the Outer Continental Shelf, including the Gulf of Mexico. If the BOEM determines that a company does not have the financial ability to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance.

Air emissions and climate change. The U.S. Clean Air Act 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 gas sector due to their association with climate change. In addition, international climate efforts, including the 2015 "Paris Agreement" and the 2021 and 2022 Conferences of the Parties of the UN Framework Convention on Climate Change (COP26 and COP27, respectively), have resulted in commitments from many countries to reduce GHG emissions and have called for parties to eliminate certain fossil fuel subsidies and pursue further action on non-carbon dioxide GHGs.

Murphy is currently required to report GHG emissions from its U.S. operations in the Gulf of Mexico and onshore in south Texas and in its Canadian onshore business in British Columbia and Alberta. In British Columbia and Alberta, Murphy is subject to a carbon tax on the purchase or use of many carbon-based fuels. Additionally, starting in 2017, a carbon tax began to be applied to certain operations in Alberta. Any 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.

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.

<u>Health and Safety</u>

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

Response to COVID-19. During the COVID-19 pandemic, a proactive approach was taken by Murphy and we adopted strict protocols to protect our employees and their families, contractors and the communities in which we work from the virus. Our response program was led by our Incident Management Team (IMT), under the guidance of our Crisis Management Team (CMT), leveraging the advice and recommendations of infectious disease experts and establishing safety protocols for all workers.

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

Human Capital Management

At Murphy, we believe in providing energy that empowers people, and that is what our 691 employees do every day. As of December 31, 2022, we had 400 office-based employees and 291 field employees, all of whom are guided by our mission, vision, values and behaviors. Together with the Executive Leadership Team, the Vice President of Human Resources and Administration, who reports directly to our President and Chief Executive Officer, is responsible for developing and executing our human capital management strategy. This includes the attraction, recruitment, development and engagement of talent to deliver on our strategy, the design of employee compensation, health and welfare benefits, and talent programs. We focus on the following factors in order to implement and develop our human capital strategy:

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

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

Employee Compensation Programs

Our purpose, to empower people, includes tying a portion of our employees' pay to performance in a variety of ways, including incentive compensation and performance-based bonus programs, while maintaining the best interest of stockholders. We benchmark for market practices, and regularly review our compensation against the market to ensure it remains competitive to attract and retain the best talent. We believe our current practices align our employees' compensation with the interests of our stockholders, and support our focus on cash flow generation, capital return and environmental stewardship. For further detail on the Company's compensation framework please see the Compensation Discussion and Analysis section of the forthcoming Proxy Statement relating to the Annual Meeting of Stockholders on May 10, 2023.

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
- Maintain a process that is consistent throughout the organization to measure employee performance and is tied to Company and stockholder 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/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 at Murphy. Through our digital platform, My Murphy Learning, employees can access self-directed courses, external articles and videos that cover topics such as business, technology and productivity. We also administer mandatory compliance training for our employees through My Murphy Learning, with a 100% utilization. Further, we strive to empower our leadership, so we sponsor several programs to address career advancement for emerging leaders. Plus, we provide a tuition reimbursement program for those who choose to acquire additional knowledge to increase their effectiveness in their present position or to prepare for career advancement. Murphy holds internal technical ideas forums each year designed to share best practice and technical advances across the Company, including safety and environmental topics.

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

To 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 2022, our voluntary employee turnover rate was 10.5%.

Health and Welfare Benefits

We believe that doing our part to aid in maintaining the health and welfare of our employees is a critical element in Murphy achieving success. As such, we provide our employees and their families with a comprehensive set of subsidized benefits that are competitive and aligned to Murphy's mission, vision, values and behaviors. We also believe that the well-being of our employees is enhanced when they can give back to their local communities or charities either through the Company "Impact – Murphy Makes a Difference" program or on their own and receive a Company match for donations.

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

Diversity, Equity and Inclusion

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

We seek input and program recommendations from our DE&I Committee with the support of the Executive Leadership team and through the sponsorship of our Vice President, Human Resources and Administration. Our DE&I Committee consists of diverse employees at various levels from across the organization that share a passion for DE&I. Our Board currently includes three women directors with at least one female director on each committee. Our Nominating and Governance Committee is actively focused on DE&I issues as part of its overall mandate.

Female Representation (U.S. and International)	December 31, 2022
Executive and Senior Level Managers	16 %
First- and Mid-Level Managers	23 %
Professionals	35 %
Other (Administrative Support and Field)	5 %
Total	**21 %**

Minority [1] Representation (U.S.-Based Only)	December 31, 2022
Executive and Senior Level Managers	26 %
First- and Mid-Level Managers	26 %
Professionals	39 %
Other (Administrative Support and Field)	30 %
Total	**33 %**

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

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

Environmental, Social and Governance (ESG) Disclosure

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

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 2022, we published our fourth annual sustainability report, located on the Company's website.

Website Access to SEC Reports

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

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

Item 1A. RISK FACTORS

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

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

Price Risk Factors

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

Among the most significant variable factors impacting the Company's results of operations are the sales prices for crude oil and natural gas that it produces. Many of the factors influencing prices of crude oil and natural gas are beyond our control. These factors include:

- the occurrence or threat of epidemics or pandemics, such as the outbreak of coronavirus disease 2019 (COVID-19), or any government response to such occurrence or threat which may lower the demand for hydrocarbon fuels;
- worldwide and domestic supplies of, and demand for, crude oil, natural gas liquids and natural gas;
- the ability of the members of OPEC and certain non-OPEC members, for example, Russia, to agree to maintain or adjust production levels;
- the production levels of non-OPEC countries, including, amongst others, production levels in the shale plays in the United States;
- political instability or armed conflict in oil and natural gas producing regions, such as the Russia-Ukraine 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 gas exploration, development, and production activities and considerations including climate change and the transition to a lower carbon economy;
- domestic and foreign governmental regulations and taxes, including further legislation requiring, subsidizing or providing tax benefits for the use 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 $94 per barrel in 2022, compared to $68 in 2021, $39 in 2020 and $57 in 2019. 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 $6.38 per million British Thermal Units (MMBTU) in 2022, compared to $3.84 in 2021 and $1.99 in 2020. The Company also has exposure to the Canadian benchmark natural gas price, AECO, which averaged US$4.09 per MMBTU in 2022, compared to US$2.89 in 2021 and US$1.66 in 2020. The Company has entered into certain forward fixed price contracts as detailed in the Outlook section on page 54 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. The Company may hedge a portion of its exposure to the effects of changing prices of crude oil and natural gas by selling forwards, swaps and other forms of derivative contracts.

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

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

See Note L 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 L 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 subjects 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's strategy is to participate in three to five exploration wells per year. In 2022, the Company participated in two exploration wells, the Cutthroat well located in Brazil and the Tulum-1EXP well located in Mexico, that failed to encounter commercial hydrocarbons. In addition, in December of 2022, the Company commenced drilling of the Oso-1 well in the Gulf of Mexico, with drilling to continue through the first quarter of 2023. The Company has budgeted $100 million for its 2023 exploration program, which includes finishing the Oso-1 well and drilling two additional Gulf of Mexico operated exploration wells.

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 liquids (NGL) and natural gas included in this report on pages 110 through 119 have been prepared according to the SEC guidelines by qualified Company personnel or qualified independent engineers based on an unweighted average of crude oil, NGL and natural gas prices in effect at the beginning of each month of the respective year as well as other conditions and information available at the time the estimates were prepared. Estimation of reserves is a subjective process that involves professional judgment by engineers about volumes to be recovered in future periods from underground oil and natural gas reservoirs. Estimates of economically recoverable crude oil, NGL and natural gas reserves and future net cash flows depend upon a number of variable factors and assumptions, and consequently, different engineers could arrive at different estimates of reserves and future net cash flows based on the same available data and using industry accepted engineering practices and scientific methods. In 2022, 98.0% 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, 2022, and including noncontrolling interests, approximately 31% of the Company's crude oil and condensate proved reserves, 29% of natural gas liquids proved reserves and 47% 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 123 and 124 should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles (GAAP), the estimated discounted future net revenues from our proved reserves are based on an unweighted average of the oil and natural gas prices in effect at the beginning of each month during the year. Actual future prices and costs may be materially higher or lower than those used in the reserves computations.

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

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

Certain of the Company's major oil and natural gas producing properties are operated by others. Therefore, Murphy does not fully control all activities at certain of its revenue generating properties. During 2022, approximately 21% of the Company's total production was at fields operated by others, while at December 31, 2022, approximately 15% of the Company's total proved reserves were at fields operated by others.

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

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

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

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

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. 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.

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 GHG emissions; wildlife, habitat and water protection; 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. It is possible in the future, certain regulatory bodies such as the Railroad Commission of Texas may enact regulation that bans or reduces flaring for 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 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's onshore North America oil and natural gas production is dependent on a technique known as hydraulic fracturing whereby water, sand and certain chemicals are injected into deep oil and natural gas bearing reservoirs in North America. This process occurs thousands of feet below the surface and creates fractures in the rock formation within the reservoir which enhances migration of oil and natural gas to the wellbore. The Company primarily uses this technique in the Eagle Ford Shale in South Texas and in 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.

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

In addition, BOEM and BSEE have regulations applicable to lessees in federal waters that impose various safety, permitting and certification requirements applicable to exploration, development and production activities in the Gulf of Mexico, and also require lessees to have substantial U.S. assets and net worth or post bonds or other acceptable financial assurance that the regulatory obligations will be met. These include, in the Gulf of Mexico, well design, well control, casing, cementing, real-time monitoring, and subsea containment, among other items. Under applicable requirements, BOEM evaluates the financial strength and reliability of lessees and operators active on the OCS. If the BOEM determines that a company does not have the financial ability to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance.

In addition, various executive orders by the current presidential administration and the Department of Interior over the course of 2021 regarding a temporary suspension of normal-course issuance of permits for fossil fuel development on federal lands and a pause on new oil and gas leases on public lands and offshore waters, and the Secretary of Interior's related review of permitting and leasing practices, could adversely impact Murphy's operations. Despite the pauses on oil and gas leases in 2021, in August 2022, the Inflation Reduction Act 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 Mexico and Alaska within two years. These developments demonstrate the uncertainty regarding the current presidential administration's approach to oil and gas leasing and permitting. 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 gas exploration, development, and production activities and sustainability considerations, including climate change and the transition to a lower carbon economy.

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

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

While the Company has been named a co-defendant with other oil and 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. In November 2022, the Company entered into an $800 million revolving credit facility (RCF). The RCF is a senior unsecured guaranteed facility and will expire in November 2027. As of December 31, 2022, the Company had no outstanding borrowings under the RCF. See Note G 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 gas sector, which, in turn, could adversely impact our cost of capital.

In 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 G for information regarding the Company's outstanding debt as of December 31, 2022.

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

The Company's worldwide operational scope exposes it to risks associated with foreign currencies. Most of the Company's business is transacted in U.S. dollars, and therefore the Company and most of its subsidiaries are U.S. dollar functional entities for accounting purposes. However, the Canadian dollar is the functional currency for all Canadian operations. This exposure to currencies other than the U.S. dollar functional currency can lead to impacts on consolidated financial results from foreign currency translation. On occasions, the Canadian business may hold assets or incur liabilities denominated in a currency which is not Canadian dollars which could lead to exposure to foreign exchange rate fluctuations. See also Note L 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 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 procurement department focused on managing supply chain and input costs. Murphy also has certain transportation, processing and production handling services costs fixed through long-term contracts and commitments and therefore is partly protected from increasing price of services. However, from time to time, Murphy will seek to enter new commitments, exercise options to extend contracts and retender contracts for rigs and other industry services which could expose Murphy to the impact of higher prices.

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

Murphy is exposed to credit risk in three principle areas:

- Accounts receivable credit risk from selling its produced commodity to customers;
- Joint venture partners related to certain oil and natural gas properties operated by the Company. These joint venture partners may not be able to meet their financial obligation to pay for their share of capital and operating costs as they become due; and
- Counterparty credit risk related to forward price commodity hedge contracts to protect the Company's cash flows against lower oil and natural gas prices.

To mitigate these risks the Company:

- Actively monitors the credit worthiness of all its customers, joint venture partners and forward commodity hedge counterparties; and
- Given the inherent credit risks in a cyclical commodity price business, the Company has increased the focus on its review of joint venture partners, the magnitude of potential exposure and planning suitable actions should a joint venture partner fail to pay its share of capital and operating expenditures.

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

General Risk Factors

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

As the COVID-19 pandemic has evolved from its emergence in early 2020, so has its global impact. In 2020 the spread of COVID-19 led to disruption in the global economy and weakness in demand in crude oil, natural gas liquids and natural gas, which applied downward pressure on global commodity prices. The combination of vaccine availability and the relaxation of government-imposed lockdowns in 2021 led to a rebound in global economic activity in 2021, which continued throughout 2022.

However, the future impact of COVID-19, or that of any other pandemic, 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 liquids and natural gas can significantly affect the Company's operating results."

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

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

We continue to work with our stakeholders (including customers, employees, suppliers, financial and lending institutions and local communities) to address the COVID-19 pandemic responsibly. We continue to monitor the situation, to assess further possible implications to our business, supply chain and customers, and to take actions in an effort to mitigate adverse consequences. The Company continues to exercise financial discipline in managing costs and capital expenditures.

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

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 United States under federal, state and local jurisdictions and in the foreign jurisdictions in which we operate. Tax laws, regulations 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 or earnings in a given taxing jurisdiction or our ownership or capital structure. For example, on August 16, 2022, the United States enacted the Inflation Reduction Act of 2022, which is highly complex, subject to interpretation and contains significant changes to U.S. tax law, including, but not limited to, a 15% corporate book minimum tax for taxpayers with adjusted financial statement income in excess of $1 billion and a 1% excise tax on certain stock repurchases made after December 31, 2022. The U.S. Department of the Treasury and the IRS are expected to release further regulations and interpretive guidance implementing the legislation contained in the Inflation Reduction Act of 2022, but the details and timing of such regulations are subject to uncertainty at this time. The tax provisions of the Inflation Reduction Act of 2022 that may apply to us are generally effective in 2023 or later and therefore tax impacts to us in 2022 were immaterial. We continue to analyze the potential impact of the Inflation Reduction Act of 2022 on our consolidated financial statements and to monitor guidance to be issued by the U.S. Department of the Treasury. However, it is possible that the enactment of changes in the U.S. corporate tax system, including in connection with the Inflation Reduction Act of 2022, could have a material effect on our consolidated cash taxes in the future.

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

The oil and gas industry has become increasingly dependent on digital technologies to conduct exploration, development, and production activities. We are no exception to this trend. As a company, we depend on these technologies to estimate quantities of oil and natural gas reserves, process and record financial and operating data, analyze seismic and drilling information, communicate internally and externally, and conduct many other business activities.

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

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

- People - Security awareness education and readiness-testing throughout the year for employees and contractors;
- Process - Incorporating “cyber awareness” in our day to day processes and maturing key controls such as recurring internal and external cyber risk assessments, physical and digital asset protection, and security vulnerability remediation via preventative and detective measures; and
- Technology - Investing in industry aligned security technology and threat intelligence capabilities.

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

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

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

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

In addition, the current presidential administration has pursued other initiatives related to environmental, health and safety standards applicable to the oil and gas industry. These include an executive order in January 2021 that directed the Secretary of the Interior to halt indefinitely new oil and gas leases on federal lands and offshore waters pending a since-completed review by the Secretary of the Interior of federal oil and gas permitting and leasing practices; however, a June 2021 preliminary injunction in the U.S. District Court for the Western District of Louisiana barred the current presidential administration from implementing the pause in new federal oil and gas leases. This executive order also set forth other initiatives and goals, including procurement of carbon pollution-free electricity, elimination of fossil fuel subsidies, a carbon pollution-free power sector by 2035 and a net-zero emissions U.S. economy by 2050. Another executive order from January 2021 called for a climate change-focused review of regulations and other executive actions promulgated, issued or adopted during the prior presidential administration. In August 2022, the Inflation Reduction Act 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 Mexico and Alaska within two years. These developments demonstrate the uncertainty regarding the current presidential administration's approach to oil and gas leasing and permitting.

In March 2022, the SEC proposed rules requiring disclosure of a 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, Scope 2 and (for certain companies) Scope 3 emissions. The SEC's proposed climate disclosure rules have not yet been finalized, but implementation of the rules as proposed could be costly and time consuming.

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

Prices and availability of crude oil, natural gas and refined products could be influenced by political factors and by various governmental policies to restrict or increase petroleum usage and supply. Other governmental actions that could affect Murphy's operations and earnings include expropriation, tax law changes, royalty increases, redefinition of international boundaries, preferential and discriminatory awarding of oil and natural gas leases, restrictions on drilling and/or production, restraints and controls on imports and exports, safety, and relationships between employers and employees. Governments could also initiate regulations concerning matters such as currency fluctuations, currency conversion, protection and remediation of the environment, and concerns over the possibility of global warming caused by the production and use of hydrocarbon energy. As of December 31, 2022, 0.1% of the Company's proved reserves, as defined by the SEC, were located in countries other than the U.S. and Canada.

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

Additionally, because of the numerous countries in which the Company operates, certain other risks exist, including the application of the U.S. Foreign Corrupt Practices Act and other similar anti-corruption compliance statutes in the jurisdictions in which we operate.

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

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

Murphy maintains insurance against certain, but not all, hazards that could arise from its operations. The Company maintains liability insurance sufficient to cover its share of gross insured claim costs up to approximately $500 million per occurrence and in the annual aggregate. Generally, this insurance covers various types of third-party claims related to personal injury, death and property damage, including claims arising from "sudden and accidental" pollution events. The Company also maintains insurance coverage for property damage and well control with an additional limit of $450 million per occurrence ($850 million for U.S. Gulf of Mexico claims), all or part of which could apply to certain sudden and accidental pollution events. These policies have deductibles ranging from $10 million to $25 million. The occurrence of an event that is not insured or not fully insured could have a material adverse effect on the Company's financial condition and results of operations in the future.

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

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 and, 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 oil and liquids. The issue of climate change has caused considerable attention to be directed towards initiatives to reduce global GHG emissions. The Paris Agreement and subsequently yearly "conferences of the parties" to the Paris Agreement 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. Most recently, in November 2022, the international community gathered in Egypt at the 27th Conference of the Parties on the UN Framework Convention on Climate Change (COP27), during which multiple announcements were made, including the EPA's announcement of more stringent revisions to previously proposed methane emissions rules for the oil and gas sector. The previously proposed rules and EPA's November 2022 revisions, establish requirements for methane emissions from existing and modified oil and gas sources and impose additional requirements for new sources. In addition, the federal government could issue various executive orders that may result in additional laws, rules and regulations in the area of climate change. It is possible that the Paris Agreement, COP27, government 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 initiatives that aim to subsidize the development of non-fossil fuel energy sources, may reduce the competitiveness of carbon-based fuels, such as oil and gas. While the magnitude of any reduction in hydrocarbon demand is difficult to predict, such a development could adversely impact the Company and other companies engaged in the exploration and production business. With or without renewable-energy subsidies, the unknown pace and strength of technological advancement of non-fossil-fuel energy sources creates uncertainty about the timing and pace of effects on our business model. The Company continually monitors the global climate change agenda initiatives and plans accordingly based on its assessment of such initiatives on its business.

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

The Company or certain of its consolidated subsidiaries are involved in numerous legal proceedings, including lawsuits for alleged personal injuries, 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 U.S. Securities and Exchange Commission as of December 31, 2022.

Item 2. PROPERTIES

Descriptions of the Company's oil and natural gas properties are included in Item 1 of this Form 10-K report beginning on page 1. Information required by the Securities Exchange Act Industry Guide No. 2 can be found in the Supplemental Oil and Gas Information section of this Annual Report on Form 10-K on pages 110 to 125 and in Note D beginning on page 80.

Item 3. LEGAL PROCEEDINGS

Discussion of the Company's legal proceedings are included in Note R beginning on page 103.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Information about our Executive Officers

Present corporate office, length of service in office and age at February 1, 2023 of each of the Company's executive officers are reported in the following listing. Executive officers are elected annually, but may be removed from office at any time by the Board of Directors.

Roger W. Jenkins – Age 61; President and Chief Executive Officer since 2013. Mr. Jenkins served as Chief Operating Officer from 2012 to 2013.

Thomas J. Mireles – Age 50; 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.

Eric M. Hambly – Age 48; Executive Vice President, Operations since 2020. Mr. Hambly served as Executive Vice President, Onshore from 2018 to 2020 and Senior Vice President, U.S. Onshore of Murphy Exploration & Production Company from 2016 to 2018.

E. Ted Botner – Age 58; Senior Vice President, General Counsel and Corporate Secretary since 2020. Mr. Botner was Vice President, Law and Corporate Secretary from 2015 to 2020 and Manager, Law and Corporate Secretary from 2013 to 2015.

Daniel R. Hanchera - Age 65; Senior Vice President, Business Development since December 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 54; 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 46; Vice President, Corporate Planning and Treasurer since July 2022. Mr. Jumawan was Assistant Treasurer from 2017 to 2022.

Maria A. Martinez – Age 48; 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 49; Vice President, Sustainability since February 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 57; Vice President, Tax since 2018.

Paul D. Vaughan – Age 56, Vice President and Controller since July 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 57; Vice President, Investor Relations and Communications since 2015.

PART II

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

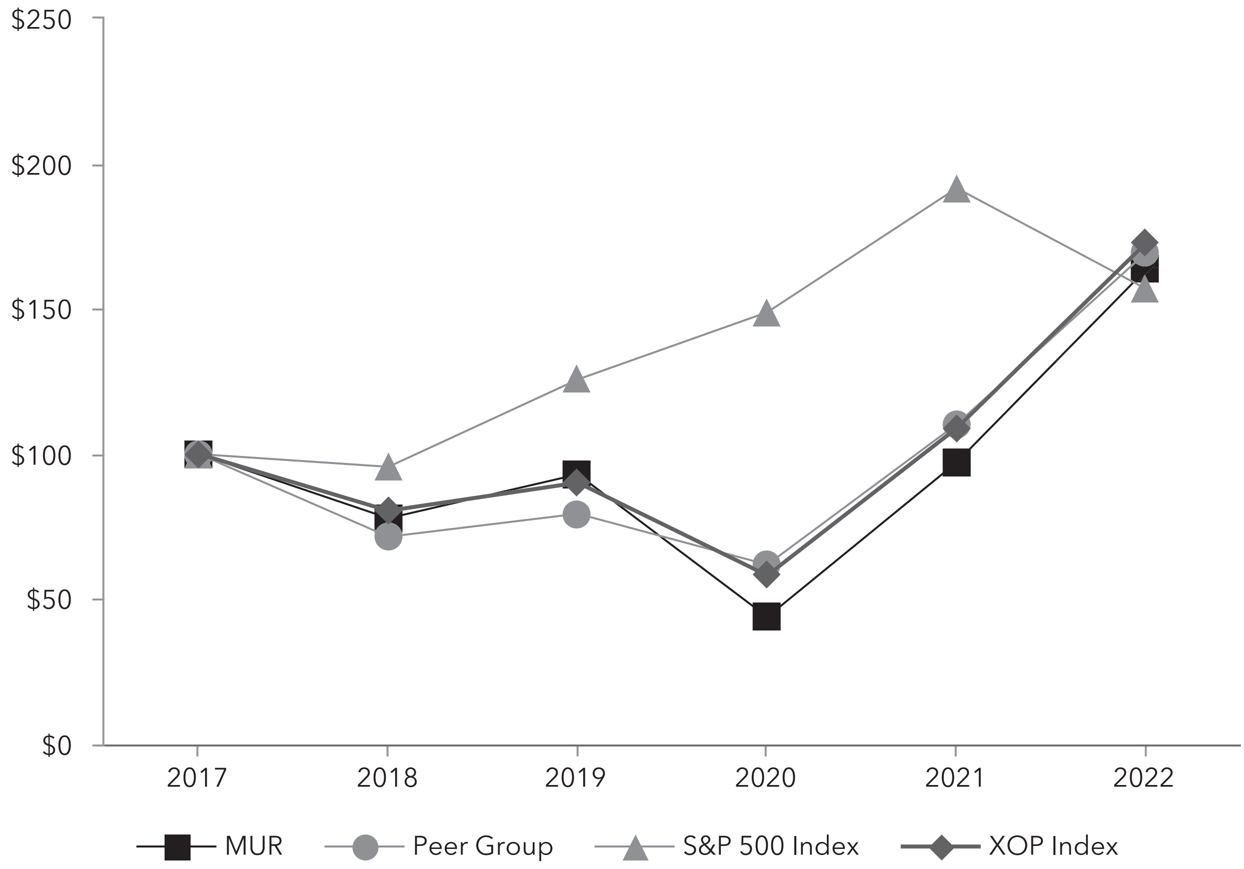
The Company's Common Stock is traded on the New York Stock Exchange using "MUR" as the trading symbol. There were 2,063 stockholders of record as of December 31, 2022. Information on dividends per share by quarter for 2022 and 2021 are reported on page 126 of this Form 10-K report.

SHAREHOLDER RETURN PERFORMANCE PRESENTATION

The following graph presents a comparison of cumulative five-year shareholder returns (including the reinvestment of dividends) as if a $100 investment was made on December 31, 2017 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 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. This performance information is "furnished" by the Company and is not considered as "filed" with this Form 10-K report and it is not incorporated into any document that incorporates this Form 10-K report by reference. The companies in the peer group included:

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

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN



	2017	2018	2019	2020	2021	2022
Murphy Oil Corporation	100	78	93	44	97	164
Peer Group	100	72	79	62	110	169
S&P 500 Index	100	96	126	149	192	157
XOP Index	100	81	90	58	109	173

Item 6. RESERVED

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

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

In 2022, a combination of demand recovery from the COVID-19 pandemic, geopolitical uncertainty and market disruption from the Russia/Ukraine conflict and lack of investment in the exploration and production sector contributed to increased crude oil and natural gas benchmark prices compared to 2021. Prices declined in the second half of 2022, due to increased supply related to the Strategic Petroleum Reserve oil release and ongoing concerns related to a possible economic slowdown and demand from China.

Similar to the overall inflation in the wider economy, the oil and gas industry, and hence the Company, is observing higher costs for goods and services used in exploration and production operations. Murphy continues to manage input costs through its dedicated procurement department focused on managing supply chain and other costs.

Significant Company operating and financial highlights during and at the end of 2022 were as follows:

- Generated net income of $965 million and $2,180.2 million of net cash provided by operating activities and $1,070.8 million of adjusted cash flow[1];
- Produced 175 thousand barrels of oil equivalent (BOE) per day (167 thousand excluding noncontrolling interest, NCI) and completed the Khaleesi, Mormont, Samurai field development project in the Gulf of Mexico with seven wells brought online;
- Acquired additional working interest in non-operated Lucius and Kodiak fields in the Gulf of Mexico for $128.5 million;
- Announced capital allocation framework [2] and reduced total debt by approximately $650 million, a 26% debt reduction in the year;
- Doubled the cash dividend since the fourth quarter of 2021 to $1.00 per share annualized; and
- Achieved 98% total proved reserve replacement with year-end proved reserves of 715.4 million barrels of oil equivalent (697.2 million excluding NCI).

[1] Adjusted cash flow is a non-GAAP financial measure calculated as cash flow from operations less capital expenditures ($1,109.4 million). Management believes adjusted cash flow is important to provide as it is used by management to evaluate the Company's ability to generate additional cash from business operations after providing for capital investments. Adjusted cash flow is a non-GAAP financial measure and should not be considered a substitute for other financial measures as determined in accordance with accounting principles generally accepted in the United States of America. Additionally, our definition of adjusted cash flow is limited and does not represent residual cash flows available for other discretionary expenditures as the measure does not deduct the payments required for debt service and other obligations. Therefore, we believe it is important to view adjusted cash flow as supplemental to our entire statement of cash flows.

[2] Details of the capital allocation framework can be found as part of the Company's Form 8-K filed on August 4, 2022.

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

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

Changes in the price of crude oil and natural gas have a significant impact on the profitability of the Company. In 2022, liquids from continuing operations represented approximately 62% of total hydrocarbons produced on an energy equivalent basis. In 2023, the Company's ratio of hydrocarbon production represented by liquids is expected to be 63%. If the prices for crude oil and natural gas are lower in 2023 or beyond, this will have an unfavorable impact on the Company's operating profits; likewise, if prices are higher, this will have a favorable impact. The Company, from time to time, may choose to use a variety of commodity hedge instruments to reduce commodity price risk, including forward sale fixed financial swaps and long-term fixed-price physical commodity sales.

Oil prices were higher in 2022 compared to the 2021 and 2020 periods. The sales price of a barrel of West Texas Intermediate (WTI) crude oil averaged $94.23 in 2022, $67.91 in 2021 and $39.40 in 2020. In 2023, the WTI price has thus far been below the comparable period in 2022, however, higher than the comparable period 2021.

WTI average price for 2022 increased 39% over the prior year principally as a result of demand recovery from the COVID-19 pandemic, geopolitical uncertainty and market disruption following the Russia/Ukraine conflict and market concerns over supply shortfalls as discussed above.

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 New York Mercantile Exchange (NYMEX) natural gas price per million British Thermal Units (MMBTU) averaged $6.38 in 2022, $3.84 in 2021 and $1.99 in 2020. The 2022 NYMEX natural gas price was higher compared to 2021 and NYMEX prices in 2023 have thus far been below the comparable period in 2022.

Results of Operations

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

	Years Ended December 31,		
(Millions of dollars, except EPS)	**2022**	2021	2020
Income (loss) from continuing operations before income taxes	**$ 1,450.3**	$ 42.9	$ (1,549.0)
Net income (loss) attributable to Murphy	**965.0**	(73.7)	(1,148.8)
Diluted EPS	**6.13**	(0.48)	(7.48)
Income (Loss) from continuing operations attributable to Murphy	**967.1**	(72.4)	(1,141.6)
Diluted EPS	**6.14**	(0.47)	(7.43)
(Loss) income from discontinued operations	**(2.1)**	(1.2)	(7.2)
Diluted EPS	**(0.01)**	(0.01)	(0.05)

For the year ended December 31, 2022, the Company produced 175 thousand barrels of oil equivalent per day (including noncontrolling interest) from continuing operations. The Company invested $1,183.2 million in capital expenditures (on a value of work done basis) for the year ended December 31, 2022, which included $25.9 million attributable to noncontrolling interest and $128.5 million for capital acquisitions. The Company reported net income from continuing operations of $1,140.8 million for the year ended December 31, 2022. This amount includes income attributable to noncontrolling interest of $173.7 million, after-tax gains on unrealized mark to market revaluations on commodity price swap and collar positions of $169.6 million and after-tax losses on contingent consideration (see Note P) of $61.6 million.

In 2022, the Company achieved first production from the Khaleesi, Mormont, Samurai field development project in the Gulf of Mexico and acquired a 3.4% working interest in the Lucius field and an 11.0% working interest in the Kodiak field in the Gulf of Mexico, with both acquisitions having no noncontrolling interests.

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

Other Key Performance Metrics

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

	Year Ended December 31,		
(Millions of dollars, except per barrel of oil equivalents sold)	**2022**	2021	2020
Net (loss) income attributable to Murphy (GAAP)	**$ 965.0**	$ (73.7)	$ (1,148.8)
Income tax expense (benefit)	**309.5**	(5.9)	(293.7)
Interest expense, net	**150.8**	221.8	169.4
Depreciation, depletion and amortization expense [1]	**748.2**	760.6	932.6
EBITDA attributable to Murphy (Non-GAAP)	**2,173.5**	902.8	(340.5)
Mark-to-market (gain) loss on derivative instruments	**(214.7)**	112.1	69.3
Mark-to-market loss (gain) on contingent consideration	**78.3**	63.2	(13.8)
Foreign exchange (gain) loss	**(23.0)**	(1.0)	0.7
Loss (gain) on sale of assets [1]	**(14.5)**	–	–
Accretion of asset retirement obligations [1]	**40.9**	41.1	42.1
Write-off of previously suspended exploration wells	**22.7**	–	–
Asset retirement obligation losses (gains)	**30.8**	(71.8)	(2.8)
Discontinued operations loss	**2.1**	1.2	7.2
Impairment of assets [1]	**–**	196.3	1,072.5
Unutilized rig charges	**–**	8.7	16.0
Restructuring expenses	**–**	–	50.0
Inventory loss	**–**	–	8.3
Insurance Proceeds	**–**	–	(1.7)
Adjusted EBITDA attributable to Murphy (Non-GAAP)	**$ 2,096.1**	$ 1,252.6	$ 907.3
Total barrels of oil equivalents sold from continuing operations attributable to Murphy (thousands of barrels)	**60,837**	57,476	60,189
Adjusted EBITDA per barrel of oil equivalents sold	**$ 34.45**	$ 21.79	$ 15.07

[1] Depreciation, depletion and amortization expense, impairment of assets, loss (gain) on sale of sale of assets and accretion of asset retirement obligations used in the computation of adjusted EBITDA exclude the portion attributable to the non-controlling interest.

Segment Results – In the following table, the Company's results of operations for the three years ended December 31, 2022, are presented by segment. More detailed reviews of operating results for the Company's exploration and production and other activities follow the table.

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

(Millions of dollars)		2022		2021		2020
Exploration and production – continuing operations						
United States	$	1,521.9	$	766.3	$	(1,014.3)
Canada		134.2		(16.1)		(35.0)
Other International		(77.0)		(33.5)		(85.6)
Total exploration and production – continuing operations		1,579.1		716.7		(1,134.9)
Corporate and other		(438.3)		(668.0)		(120.3)
Income (loss) from continuing operations		1,140.8		48.7		(1,255.2)
(Loss) income from discontinued operations		(2.1)		(1.2)		(7.2)
Net income (loss) including noncontrolling interest		1,138.7		47.5		(1,262.4)
Net income (loss) attributable to noncontrolling interest		173.7		121.2		(113.7)
Net income (loss) attributable to Murphy	$	965.0	$	(73.7)	$	(1,148.7)

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

(Millions of dollars)			2022		2021		2020
United States	Oil and natural gas liquids	$	3,210.3	$	2,199.7	$	1,335.8
	Natural gas		225.2		121.7		69.4
Canada	Oil and natural gas liquids		267.5		228.9		174.0
	Natural gas		312.6		245.9		170.6
Other	Oil		22.8		4.9		1.8
Total oil and natural gas revenues		$	4,038.4	$	2,801.1	$	1,751.6

Exploration and Production

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

2022 vs 2021

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

Exploration and production (E&P) from continuing operations recorded earnings of $1,579.1 million in 2022 compared to earnings of $716.7 million million in 2021. Results were favorable $862.4 million in 2022 compared to 2021 primarily due to higher oil, natural gas liquid and natural gas prices and volumes, lower impairment charges and lower depreciation, depletion and amortization (DD&A) expense, partially offset by higher lease operating expenses (LOE), other operating expense, exploration expenses, transportation, gathering and processing, severance and ad valorem taxes and income tax charges. See below for further details.

E&P crude oil price realizations averaged $94.89 per barrel in 2022 compared to $66.80 per barrel in 2021, an increase of 42% year over year. U.S. natural gas realized price per thousand cubic feet (MCF) averaged $6.68 in the current year compared to $3.71 per MCF in 2021, an increase of 80% year over year. Canada natural gas realized price per MCF averaged U.S. $2.76 in 2022compared to U.S. $2.43 per MCF in 2021, an increase of 14% year over year. E&P oil and natural gas LOE and severance and ad valorem taxes (production costs), on a per-unit basis, were $11.55 in 2022 (2021: $9.53). The increase in per-unit production costs in 2022 was primarily attributable to cost increases from inflationary pressures related to the onshore business and higher production from the Khaleesi and Mormont assets.

United States E&P operations reported earnings of $1,521.9 million in 2022 compared to earnings of $766.3 million in 2021. Results were favorable $755.6 million in 2022 compared to the 2021 period driven by higher total revenues ($1,123.7 million), partially offset by higher LOE ($116.3 million), income tax expense ($186.9 million), other operating expense ($26.9 million), severance and ad valorem taxes ($16.1 million) and transportation, gathering and processing costs ($15.7 million).

Higher revenues are primarily attributable to higher realized prices in 2022 compared to 2021 and higher sales volumes (4,026 barrels of oil equivalent per day higher) which includes additional sales volumes from the Khaleesi, Mormont, Samurai field development project in the Gulf of Mexico. Higher LOE relates to higher production volumes, cost increases from inflationary pressures related to the onshore business and higher production handling fees at the Khaleesi and Mormont assets. Higher income tax expense is a result of higher pre-tax income. Increases in other operating expenses is primarily due to a higher asset retirement adjustments related to non-producing fields, ($37.2 million) and higher unfavorable mark to market revaluation on contingent consideration ($15.1 million) from prior Gulf of Mexico acquisitions. Higher severance and ad valorem taxes are due to higher revenues at Eagle Ford Shale and higher transportation, gathering and processing costs are due to higher sales volumes at the Gulf of Mexico.

Canadian E&P operations reported earnings of $134.2 million in 2022 compared to a loss of $16.1 million in 2021. Results were favorable $150.3 million compared to 2021 primarily due to higher revenue from production ($105.1 million), no impairment charges in 2022 (2021:$171.3 million) and lower DD&A ($22.3 million), partially offset by higher other operating expense ($78.6 million), higher income tax charges ($45.3 million), higher LOE ($18.8 million) and higher transportation, gathering and processing ($10.0 million).

Higher revenue is primarily attributable to higher realized prices and higher gas volumes (new wells added in 2022). Lower impairment and higher other operating expense in 2022 was the result of the 2021 impairment charge for Terra Nova. The impairment charge was recorded in the first quarter of 2021 following notice from the operator of asset abandonment at Terra Nova at the time of the assessment, which was later partially offset with a credit of $71.8 million in the third quarter of 2021 which was reported in 'other operating expense' as a result of the deferral of an asset retirement obligation at Terra Nova following the sanction of an asset life extension project and reversal of the asset abandonment decision. Higher income tax expense is a result of higher pre-tax income. Higher LOE is due to higher gas volumes and higher processing rates at Tupper Montney. Increased transportation, gathering and processing expense is due to higher sales volumes and an increase in transportation rates at Tupper Montney.

Other international E&P operations reported a loss from continuing operations of $77.0 million in 2022 compared to a loss of $33.5 million in 2021. Results were unfavorable $43.5 million in 2022 compared to 2021 and were largely driven by higher exploration expenses ($57.7 million) and higher income tax charges ($12.4 million), partially offset by lower impairment charges ($18.0 million) and higher revenues ($17.9 million). Exploration expenses in 2022 primarily relate to the Cutthroat-1 exploration well in block SEAL-M-428 in the Sergipe-Alagoas Basin offshore Brazil and the Tulum-1EXP exploration well in Block 5 in the Salina Basin offshore Mexico that failed to encounter commercial hydrocarbons.

2021 vs 2020

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

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

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

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

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

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

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

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

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

(Dollars per equivalent barrel)	**2022**	2021	2020
Continuing operations			
United States – Eagle Ford Shale			
Lease operating expense	**$ 10.97**	$ 8.96	$ 9.08
Severance and ad valorem taxes	**4.27**	2.91	2.06
DD&A expense	**25.61**	27.59	26.22
United States – Gulf of Mexico [1]			
Lease operating expense	**$ 13.19**	$ 10.63	$ 11.95
Severance and ad valorem taxes	**0.07**	0.07	–
DD&A expense	**10.12**	9.51	13.48
Canada – Onshore			
Lease operating expense	**$ 6.75**	$ 6.20	$ 4.63
Severance and ad valorem taxes	**0.06**	0.09	0.07
DD&A expense	**6.20**	7.64	9.93
Canada – Offshore			
Lease operating expense	**$ 14.20**	$ 13.04	$ 17.86
DD&A expense	**12.25**	12.80	12.01
Total E&P continuing operations			
Lease operating expense	**$ 10.65**	$ 8.86	$ 9.34
Severance and ad valorem taxes	**0.89**	0.68	0.44
DD&A expense	**12.18**	13.05	15.36
Total oil and natural gas continuing operations – excluding noncontrolling interest			
Lease operating expense	**$ 10.50**	$ 8.65	$ 9.10
Severance and ad valorem taxes	**0.93**	0.71	0.47
DD&A expense	**12.30**	13.23	15.49

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

<u>Corporate</u>

2022 vs 2021

Corporate activities, which include interest expense and income, foreign exchange effects, realized and unrealized gains and losses on derivative instruments (forward swaps and collars to hedge the price of oil sold) and corporate overhead not allocated to Exploration and Production, reported a loss of $438.3 million in 2022 compared to a loss of $668.0 million in 2021. The $229.7 million favorable variance is principally due to lower net losses on derivative instruments in 2022 compared to 2021 (2022: $320.4 million loss; 2021: $525.9 million loss), lower interest expense ($71.0 million) and higher foreign exchange gains ($26.0 million), partially offset by a lower tax benefit ($70.8 million). Realized and unrealized losses on derivative instruments are due to an increase in market pricing in future periods whereby the swap contracts provide the Company with a fixed price and the collar contracts provide for a minimum (floor) and a maximum (ceiling) price, with variability in between the floor and ceiling. As of December 31, 2022, the Company had no fixed price derivative swaps or collars contracts outstanding. Interest charges are lower in 2022 primarily due to lower overall debt and lower debt redemption costs ($8.3 million in 2022; $39.3 million in 2021) incurred by the Company. The Company reduced debt by $649.7 million in 2022. Lower income tax benefit is a result of lower pre-tax losses.

2021 vs 2020

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

Production Volumes and Prices

2022 vs 2021

Total hydrocarbon production from all E&P continuing operations averaged 175,156 barrels of oil equivalent per day in 2022, and represents a 5% increase from the 167,356 barrels per day produced in 2021. The increase is principally due to the Khaleesi, Mormont, Samurai field development project that started production in the second quarter of 2022, new wells at Tupper Montney and lower weather related downtime in 2022.

Average crude oil and condensate production from continuing operations was 97,365 barrels per day in 2022 compared to 95,705 barrels per day in 2021. The increase of 1,660 barrels per day is principally due to increased production in the Gulf of Mexico (4,694 barrels per day) with new production from Khaleesi, Mormont, Samurai field development project, partially offset by normal declines at other fields in the Gulf of Mexico. Eagle Ford Shale production is lower (1,202 barrels per day) due to lower capital expenditures in 2020 and 2021, partially offset by new wells in 2022. Canada production is lower (2,260 barrels per day) due to normal field decline at Kaybob Duvernay and Hibernia, as well as a turnaround at Hibernia. On a worldwide basis, the Company's crude oil and condensate prices average $94.89 per barrel in 2022 compared to $66.80 per barrel in the 2021 period, an increase of 42% year over year.

Total production of natural gas liquids (NGL) from continuing operations was 10,681 barrels per day in 2022 compared to 10,385 barrels per day in 2021. The average sales price for U.S. NGL was $34.87 per barrel in 2022 compared to $27.97 per barrel in 2021. The average sales price for NGL in Canada was $55.65 per barrel in 2022 compared to $40.18 per barrel in 2021. NGL prices are higher in Canada due to the higher value of product produced at the Kaybob Duvernay and Placid Montney assets.

Natural gas sales volumes from continuing operations averaged 403 MMCFD in 2022 compared to 368 MMCFD in 2021. The increase of 35 MMCFD was primarily the result of higher volumes in Canada (32.4 MMCFD) and higher volumes in the Gulf of Mexico (2.1 MMCFD). The higher natural gas volumes in Canada was the result of new wells on production in 2022. Natural gas prices for the total Company averaged $3.66 per MCF in 2022, versus $2.74 per MCF average in the same period of 2021. Average realized natural gas prices in the U.S. and Canada in 2022 were $6.68 and $2.76 per MCF, respectively. Average realized natural gas prices in Canada are lower as a result of certain fixed price sales volume contracts.

2021 vs 2020

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

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

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

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

Natural gas prices for the total Company averaged $2.74 per MCF in 2021, versus $1.85 per MCF average in 2020. Average realized natural gas prices in the U.S. and Canada in 2021 were $3.71 and $2.43 per MCF, respectively.

The following table contains hydrocarbons produced during the three years ended December 31, 2022.

(Barrels per day unless otherwise noted)		2022	2021	2020
Continuing operations				
Net crude oil and condensate				
United States	Onshore	**24,437**	25,655	26,420
	Gulf of Mexico [1]	**65,411**	60,717	64,680
Canada	Onshore	**4,005**	5,312	7,888
	Offshore	**2,812**	3,765	4,893
Other		**700**	256	85
Total net crude oil and condensate - continuing operations		**97,365**	95,705	103,966
Net natural gas liquids				
United States	Onshore	**5,181**	5,092	5,248
	Gulf of Mexico [1]	**4,597**	4,176	4,978
Canada	Onshore	**903**	1,117	1,315
Total net natural gas liquids - continuing operations		**10,681**	10,385	11,541
Net natural gas – thousands of cubic feet per day				
United States	Onshore	**29,050**	28,565	27,985
	Gulf of Mexico [1]	**63,380**	61,240	66,105
Canada	Onshore	**310,230**	277,790	260,683
Total net natural gas - continuing operations		**402,660**	367,595	354,773
Total net hydrocarbons - continuing operations including NCI [2,3]		**175,156**	167,356	174,636
Noncontrolling interest				
Net crude oil and condensate – barrels per day		**(7,452)**	(8,623)	(9,962)
Net natural gas liquids – barrels per day		**(280)**	(303)	(416)
Net natural gas – thousands of cubic feet per day [2]		**(2,468)**	(3,236)	(3,843)
Total noncontrolling interest		**(8,143)**	(9,465)	(11,019)
Total net hydrocarbons produced - continuing and discontinued operations, excluding NCI [2,3]		**167,013**	157,891	163,617
Estimated total proved net hydrocarbon reserves - million equivalent barrels [3,4]		**715.4**	716.9	714.9

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, 2022, 2021 and 2020, include 18.2 MMBOE, 18.4 MMBOE and 17.4 MMBOE, respectively, relating to noncontrolling interest.

The following table contains hydrocarbons sold during the three years ended December 31, 2022.

(Barrels per day unless otherwise noted)		**2022**	2021	2020
Continuing operations				
Net crude oil and condensate				
United States	Onshore	**24,437**	25,655	26,420
	Gulf of Mexico [1]	**64,840**	60,544	65,621
Canada	Onshore	**4,005**	5,312	7,888
	Offshore	**3,002**	3,559	4,958
Other		**663**	195	78
Total net crude oil and condensate - continuing operations		**96,947**	95,265	104,965
Net natural gas liquids				
United States	Onshore	**5,181**	5,092	5,248
	Gulf of Mexico [1]	**4,597**	4,176	4,978
Canada	Onshore	**903**	1,117	1,315
Total net natural gas liquids - continuing operations		**10,681**	10,385	11,541
Net natural gas – thousands of cubic feet per day				
United States	Onshore	**29,050**	28,565	27,985
	Gulf of Mexico [1]	**63,380**	61,240	66,105
Canada	Onshore	**310,230**	277,790	260,683
Total net natural gas - continuing operations		**402,660**	367,595	354,773
Total net hydrocarbons - continuing operations including NCI [2,3]		**174,738**	166,916	175,635
Noncontrolling interest				
Net crude oil and condensate – barrels per day		**(7,369)**	(8,605)	(10,127)
Net natural gas liquids – barrels per day		**(280)**	(303)	(416)
Net natural gas – thousands of cubic feet per day [2]		**(2,468)**	(3,236)	(3,843)
Total noncontrolling interest		**(8,060)**	(9,447)	(11,184)
Total net hydrocarbons sold - continuing and discontinued operations, excluding NCI [2,3]		**166,678**	157,469	164,451

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

The following table contains the weighted average sales prices excluding transportation cost deduction for the three years ended December 31, 2022.

		2022	2021	2020
(Weighted average Exploration and Production sales prices)				
Continuing operations				
Crude oil and condensate – dollars per barrel				
United States	Onshore	**$ 96.00**	$ 66.90	$ 36.54
	Gulf of Mexico [1]	**94.21**	66.93	39.15
Canada [2]	Onshore	**89.88**	61.79	32.42
	Offshore	**107.47**	71.39	39.40
Other		**94.37**	69.21	63.51
Natural gas liquids – dollars per barrel				
United States	Onshore	**$ 33.85**	$ 26.97	$ 11.67
	Gulf of Mexico [1]	**36.01**	29.14	10.84
Canada [2]	Onshore	**55.65**	40.18	18.54
Natural gas – dollars per thousand cubic feet				
United States	Onshore	**$ 6.04**	$ 3.83	$ 1.95
	Gulf of Mexico [1]	**6.97**	3.67	2.04
Canada [2]	Onshore	**2.76**	2.43	1.79

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

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 revolving credit facility. The Company's liquidity requirements consist primarily of capital expenditures, debt maturity, retirement and interest payments, working capital requirements, dividend payments and, as applicable, share repurchases. See below for additional discussion and analysis of the Company's cash flows.

Cash Provided by Operating Activities

Net cash provided by continuing operating activities was $2,180.2 million in 2022 compared to $1,422.2 million in 2021. The increased cash provided by continuing operating activities of $758.0 million is primarily attributable to higher revenue from sales from production ($1,237.2 million), partially offset by higher LOE ($139.8 million), higher realized losses on derivative instruments ($121.5 million) and the change in receivable and payable working capital balances ($65.7 million). Higher revenues were primarily due to higher commodity prices driven by demand recovery from COVID-19 and geopolitical uncertainty and market disruption resulting from the Russia/Ukraine conflict.

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

The total reductions of operating cash flows for interest paid (which excludes debt redemption costs reported in Financing activities) during the three years ended December 31, 2022, 2021 and 2020 were $150.0 million, $165.7 million and $191.6 million, respectively. Lower cash interest paid in 2022 was primarily due to the early redemption of $649.7 million of the 2024 notes, 2025 notes, 2028 notes and the 2042 notes. Lower cash interest paid in 2021 was due to the repayment of the $200 million outstanding on the revolving credit facility, the early redemption of the 2022 notes and the early redemption of $300 million of the 2024 notes, partially offset by interest paid on the issuance of 2028 notes in the first quarter of 2021.

Cash Used for Investing Activities

Net cash required by investing activities were $1,109.5 million and $417.7 million in 2022 and 2021, respectively. In 2022, the Company acquired additional working interest in Kodiak (11.0%) and Lucius (3.4%) for $50.0 million and $78.5 million, respectively (also see Note D). Property additions and dry hole costs (excluding King's Quay FPS), which include amounts expensed, were $985.5 million and $650.2 million in 2022 and 2021, respectively. In 2021, the Company received sales proceeds for the King's Quay FPS of $267.7 million and also acquired additional interests in the proved property Lucius for $19.9 million. In 2020, cash used by investing activities included $113 million used to fund the development of the King's Quay FPS.

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

	Year Ended December 31,		
(Millions of dollars)	**2022**	2021	2020
Capital Expenditures			
Exploration and production	**$ 1,161.5**	$ 690.1	$ 813.3
Corporate	**21.7**	21.1	13.3
Total capital expenditures	**1,183.2**	711.2	826.6
Total capital expenditures excluding proved property acquisitions	**1,054.7**	711.2	826.6
Total capital expenditures excluding proved property acquisitions and NCI	**$ 1,028.8**	$ 688.2	$ 804.9

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

(Millions of dollars)	Year Ended December 31, 2022	2021	2020
Property additions and dry hole costs per cash flow statements [1]	$ 985.5	$ 650.2	$ 759.8
Property additions King's Quay FPS per cash flow statements	–	17.7	113.0
Geophysical and other exploration expenses	30.6	26.9	32.3
Capital expenditure accrual changes and other	38.6	(3.9)	(78.5)
Acquisition of oil properties per the cash flow statements [1]	128.5	20.3	–
Total capital expenditures	$ 1,183.2	$ 711.2	$ 826.6

[1] Certain prior-period amounts have been reclassified to conform to the current period presentation.

Capital expenditures in the exploration and production business in 2022 compared to 2021 have increased and is primarily attributable to expenditures related to the Kodiak and Lucius acquisitions in the Gulf of Mexico ($128.5 million), Cutthroat-1 exploration well in Brazil ($38.4 million),Tulum-1EXP exploration well in Mexico ($21.6 million), higher capital invested at the Khaleesi, Mormont, Samurai field development project in the Gulf of Mexico, higher development drilling activities in Eagle Ford Shale and Tupper Montney assets and higher expenditures related to the asset life extension at Terra Nova.

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

Cash Used by and Provided by Financing Activities

Net cash required by financing activities was $1,081.6 million in 2022 compared to $794.5 million in 2021. In 2022, the cash required by financing activities was principally due to the early redemption of $647.7 million (excluding non cash gain of $2.0 million) of the 2024 notes, 2025 notes, 2028 notes and the 2042 notes, costs associated with early redemption ($8.3 million), distributions to noncontrolling interest ($183.0 million), dividends paid ($128.2 million) and payment of contingent consideration related to prior Gulf of Mexico acquisitions ($81.7 million). The Company anticipates the final payments for the contingent consideration liability, related to the Gulf of Mexico acquisitions, to be paid in the first half of 2023. See Note P for further details.

The primary sources of the Company's liquidity are internally generated funds, access to outside financing and working capital. The Company generally uses its internally generated funds to finance its capital and operating expenditures, but it also maintains lines of credit with banks and will borrow as necessary to meet spending requirements. As of December 31, 2022, the Company has a $800 million senior unsecured guaranteed credit facility (RCF) with a major banking consortium, which expires in November 2027. At December 31, 2022, the Company had no outstanding borrowings under the RCF and $57.6 million of outstanding letters of credit, which reduce the borrowing capacity of the RCF. If required, this provides the Company approximately $742 million availability on its RCF to fund investing activities from borrowings.

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

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

Working Capital

At the end of 2022, working capital (total current assets less total current liabilities, excluding assets and liabilities held for sale) amounted to a net working capital liability of $285.5 million (2021: net working capital liability of $298.9 million). The total working capital liability decrease of $13.4 million in 2022 is primarily attributable to higher accounts receivable, net ($133.0 million) and lower accounts payable ($79.3 million), partially offset by higher other accrued liabilities ($82.7 million), higher operating lease liabilities ($81.0 million) and lower cash and cash equivalents ($29.2 million). Higher accounts receivable are principally due to higher crude oil and natural gas pricing. Lower accounts payable is primarily due to the decrease in unrealized losses on derivative instruments (commodity price swaps and collars) which matured at the end of 2022, partially offset by higher revenue payables principally due to higher crude oil and natural gas pricing and higher trades payable related to timing of Gulf of Mexico activities. Higher other accrued liabilities are associated with higher short-term contingent consideration obligations (from prior Gulf of Mexico acquisitions) due to a reclassification from long-term liabilities. Higher operating lease liabilities are associated with a rig contract to support the Khaleesi, Mormont, Samurai field development project.

Cash and cash equivalents as of December 31, 2022 totaled $492.0 million (2021: $521.2 million). There were no borrowings from the RCF outstanding at the end of the 2022 or 2021.

Cash and invested cash are maintained in several operating locations outside the U.S. As of December 31, 2022, cash and cash equivalents held outside the U.S. included U.S dollar equivalents of approximately $147.7 million (2021: $242.9 million), the majority of which was held in Canada ($83.3 million) and Mexico ($27.7 million). In addition, approximately $12.3 million and $6.1 million of cash was held in the U.K. and Brazil, respectively. In certain cases, the Company could incur cash taxes or other costs should these cash balances be repatriated to the U.S. in future periods. Canada currently collects a 5% withholding tax on any earnings repatriated to the U.S. See Note I for further information regarding potential tax expense that could be incurred upon distribution of foreign earnings back to the United States.

Capital Employed

As of December 31, 2022, long-term debt of $1,822.4 million had decreased by $643.0 million compared to December 31, 2021, as a result the early redemption, in whole or in part, of the 2024 notes, 2025 notes, 2028 notes and the 2042 notes. The fixed-rate notes had a weighted average maturity of 7.7 years and a weighted average coupon of 6.2%.

A summary of capital employed as of December 31, 2022 and 2021 follows.

	December 31, 2022		December 31, 2021	
(Millions of dollars)	**Amount**	**%**	Amount	%
Capital employed				
Long-term debt	**$ 1,822.4**	**26.7 %**	$ 2,465.4	37.2 %
Murphy shareholders' equity	**4,994.8**	**73.3 %**	4,157.3	62.8 %
Total capital employed	**$ 6,817.2**	**100.0 %**	$ 6,622.7	100.0 %

Murphy shareholders' equity was $4.99 billion at the end of 2022 (2021: $4.16 billion). Shareholders' equity increased in 2022 primarily due to 2022 net income ($965.0 million) and a favorable revaluation of pension assets and liabilities ($99.4 million), partially offset by dividends paid ($128.2 million) and foreign currency translation losses, net of income taxes ($106.3 million). A summary of transactions in stockholders' equity accounts is presented in the Consolidated Statements of Stockholders' Equity on page 71 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 2022, compared to 2021 are discussed below.

Property, plant and equipment, net of depreciation increased $100.2 million principally due to capital expenditures in the year, partially offset by DD&A expense ($776.8 million) and foreign exchange rates applicable for our Canadian assets. Capital expenditures are discussed above in the 'Cash Used for Investing Activities' section.

Murphy had commitments for capital expenditures of approximately $282.4 million at December 31, 2022 (2021: $520.1 million). This amount includes $103.5 million for approved expenditure for capital projects relating to non-operated interests in deepwater U.S. Gulf of Mexico, principally at St. Malo ($98.9 million), non-operated Canada interests, mainly offshore ($33.3 million), non-operated Eagle Ford Shale ($13.3 million) and Brunei ($1.0 million).

Operating lease assets increased $65.0 million principally due to additions for drilling rig lease extensions, partially offset by depreciation and a decrease related to changes in foreign exchange rates applicable for our Canadian assets.

Deferred Income tax assets decreased by $267.6 million as a result of the decrease in the U.S. net operating loss carryforward of $2.10 billion at year-end 2022, down from $2.75 billion at year-end 2021.

Deferred credits and other liabilities decreased $265.6 million primarily as a result reclassification of amounts to current, a favorable pension fair value remeasurement and cash pension contributions to the plan in 2022.

At December 31, 2022, the Company had no outstanding borrowings under the RCF and $57.6 million of outstanding letters of credit, which reduce the borrowing capacity of the RCF. Borrowings under the RCF are subject to certain interest rates, please refer to Note G for further details. At December 31, 2022, the interest rate in effect on borrowings under the facility would have been 6.96%. At December 31, 2022, the Company was in compliance with all covenants related to the RCF.

Environmental, Health and Safety Matters

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

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

The principal environmental, health and safety laws and regulations to which Murphy is subject address such matters as the generation, storage, handling, use, disposal and remediation of petroleum products, wastewater and hazardous materials; the emission and discharge of such materials to the environment, including GHG emissions; wildlife, habitat and water protection; the placement, operation and decommissioning of production equipment; and the health and safety of our employees, contractors and communities where our operations are located. These laws and regulations also generally require permits for existing operations, as well as the construction or development of new operations and the decommissioning facilities once production has ceased. Violations can give rise to sanctions including significant civil and criminal penalties, injunctions, construction bans and delays.

Further information on environmental, health and safety laws and regulations applicable to Murphy are contained in the Business section beginning page 10.

Climate Change and Emissions

The world's population and standard of living is growing steadily along with the demand for energy. Murphy recognizes that this may generate increasing amounts of 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 Task Force on Climate-related Financial Disclosures (TCFD) core elements. The TCFD was created by the Financial Stability Board to focus on climate-related financial disclosures to improve and increase reporting of climate-related financial information. Murphy's disclosures related to its alignment with the TCFD are included in the Company's 2022 Sustainability Report issued on August 4, 2022, which is not incorporated by reference hereto.

Other Matters

Impact of inflation – In 2022, many countries worldwide continued to experience a rise in inflation, including countries where the Company operates (this follows a sustained period of relatively low inflation prior to 2021). In the U.S., inflation continued as a result of ongoing supply constraints and increasing demand of goods and services as countries continue their recovery from the COVID-19 pandemic. The Company's revenues, capital and operating costs are influenced to a larger extent by specific price changes in the oil and gas industry and allied industries rather than by changes in general inflation. Crude oil prices generally reflect the balance between supply and demand, with crude oil prices being particularly sensitive to OPEC+ production levels and/or attitudes of traders concerning supply and demand in the future. Costs for oil field goods and services are usually affected by the worldwide prices for crude oil.

As a result of increasing commodity prices for oil and natural gas, since the start of 2022, higher costs for goods and services in the oil and gas industry are being observed. Murphy has a dedicated procurement department focused on managing supply chain and input costs. Murphy also has certain transportation, processing and production handling services costs fixed through long-term contracts and commitments and therefore is partly protected from 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-increasing 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 demand is also impacted by demand driven by lower carbon emission and a view that natural gas is one option to transition from higher carbon emitting fuels.

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

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

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

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

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

The Company's proved reserves of crude oil, natural gas liquids and natural gas are presented on pages 110 to 119 of this Form 10-K report. Murphy's estimations for proved reserves were generated through the integration of available geoscience, engineering, and economic data (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 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, 2022 beginning on pages 4 and 110 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 make sure 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 future cash flows.

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

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

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

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

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

There were no impairments recognized in 2022. In 2021, the Company recognized pretax noncash impairment charges of $196.3 million to reduce the carrying values at select properties. In 2021, the Company recorded an impairment charge of $171.3 million for Terra Nova due to the status, including agreements with the partners, of operating and production plans and $25.0 million for assets reported as Assets held for sale in the Consolidated Balance Sheets.

See also Note D for further discussion of impairment charges.

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

As of December 31, 2022 the Company had a U.S. deferred tax asset associated with net operating losses of $442.7 million. In reviewing the likeliness of realizing this asset the Company considered the reversal of taxable temporary differences, carryforward periods and future taxable income estimates based on projected financial information which, based on currently available evidence, we believe to be reasonably likely to occur. Certain estimates and assumptions are used in the estimation of future taxable income, including (but not limited to) (a) future commodity prices for crude oil and condensate, NGLs and natural gas, (b) estimated reserves for crude oil and condensate, NGLs and natural gas, (c) expected timing of production, (d) estimated lease operating costs and (e) future capital requirements. In the future, the underlying actual assumptions utilized in estimating future taxable income could be different and result in different conclusions about the likelihood of the future utilization of our net operating loss carryforwards.

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

Based on bond yields as of December 31, 2022, the Company has used a weighted average discount rate of 5.42% at year-end 2022 for the primary U.S. plans. This weighted average discount rate is 2.6% 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 6.60% for the primary U.S. plan, it periodically reconsiders the appropriateness of this and other key assumptions. The Company's retirement and postretirement plan (health care and life insurance benefit plans) expenses in 2023 are expected to be $6.4 million higher than 2022 primarily due to the increase in the discount rate assumption for U.S. pension plan, which increases the amount of interest cost recognized in net periodic benefit expense. Cash contributions to all plans are anticipated to be $6.2 million lower in 2023.

In 2022, the Company paid $41.1 million into various retirement plans and $2.1 million into postretirement plans. In 2023, the Company is expecting to fund payments of approximately $32.2 million into various retirement plans and $4.8 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 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 2022 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**	2023	2024 - 2025	2026 - 2027	After 2027
Debt, excluding interest	**$ 1,833.6**	$ –	$ 248.7	$ 543.2	$ 1,041.7
Operating leases and other leases [1]	**1,268.6**	271.9	323.6	123.6	549.5
Capital expenditures, drilling rigs and other [2]	**1,230.5**	552.3	245.9	151.2	281.1
Other long-term liabilities, including debt interest [3]	**2,508.4**	124.4	362.6	430.2	1,591.2
Total	**$ 6,841.1**	$ 948.6	$ 1,180.8	$ 1,248.2	$ 3,463.5

1 Other leases refers to a finance lease in Brunei (see Note U to the financial statements).
2 Capital expenditures, drilling rigs and other includes $67.6 million, $33.3 million, $13.3 million and $1.1 million, in 2023 for approved capital projects in non-operated interests in U.S. Gulf of Mexico, Canada Offshore, U.S. Onshore and Other Foreign Offshore, respectively. Capital expenditures, drilling rigs and other includes $35.9 million in 2024 for approved capital projects in non-operated interests in U.S. Gulf of Mexico.
Also includes $66.5 million (2023), $105.5 million (2024 - 2025), $87.5 million (2026 - 2027) and $183.7 million (After 2027) for pipeline transportation commitments in Canada.
Also includes $5.0 million (2023), $9.8 million (2024 - 2025), $9.2 million (2026 - 2027) and $25.8 million (After 2027) for long term take or pay commitments relating to gas processing in Canada.
3 Other long-term liabilities, including debt interest includes future cash outflows for asset retirement obligations.

The Company has entered into agreements to lease production facilities for various producing oil fields as well as other arrangements that 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 $232.4 million as of December 31, 2022.

Material off-balance sheet arrangements – Certain U.S. transportation contracts require minimum monthly payments through 2045, while onshore Canada processing contracts call for minimum monthly payments through 2051. Future required minimum annual payments under these arrangements are included in the contractual obligation table above.

Outlook

Prices for the Company’s primary products are often volatile. The price of crude oil is primarily affected by the levels of supply and demand for energy. Anticipated future variances between the predicted demand for crude oil and the projected available supply can lead to significant movement in the price of crude oil. As of close on February 23, 2023, the NYMEX WTI forward curve price for the remainder of 2023 and 2024 were $75.05 and $71.85 per barrel, respectively; however we cannot predict what impact economic factors (including inflation, the Russia/Ukraine conflict and the COVID-19 pandemic) 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 2023 is expected to be between $875 million and $1025 million, excluding the amount attributable to noncontrolling interest. Capital and other expenditures are routinely reviewed and planned capital expenditures may be adjusted to reflect differences between budgeted and forecast cash flow during the year. Capital expenditures may also be affected by asset purchases or sales, which often are not anticipated at the time a budget is prepared. The Company will primarily fund its capital program in 2023 using operating cash flow and available cash. If oil and/or natural gas prices weaken, actual cash flow generated from operations could be reduced such that capital spending reductions are required and/or borrowings under available credit facilities might be required during the year to maintain funding of the Company’s ongoing development projects.

The Company currently expects average daily production in 2023 to be between 182,700 and 190,700 barrels of oil equivalent per day (including noncontrolling interest of 7,200 BOEPD). If significant price declines occur, the Company will review the option of production curtailments to avoid incurring losses on certain produced barrels.

The Company plans to utilize surplus cash (not planned to be used by operations, investing activities, dividends or payment to noncontrolling interests) in accordance with the Company’s capital allocation framework. 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.

The Company continues to monitor the impact of commodity prices on its financial position and is currently in compliance with the covenants related to the revolving credit facility (see Note G).

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

Area	Commodity	Type	Volumes (MMcf/d)	Price/MCF	Remaining Period Start Date	Remaining Period End Date
Canada	Natural Gas	Fixed price forward sales	269	C$2.36	1/1/2023	3/31/2023
Canada	Natural Gas	Fixed price forward sales	250	C$2.35	4/1/2023	12/31/2023
Canada	Natural Gas	Fixed price forward sales	162	C$2.39	1/1/2024	12/31/2024
Canada	Natural Gas	Fixed price forward sales	25	US$1.98	1/1/2023	10/31/2024
Canada	Natural Gas	Fixed price forward sales	15	US$1.98	11/1/2024	12/31/2024

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 matters, or pay and/or increase dividends or make share repurchases and other capital allocation decisions, are all 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 gas industry, including supply/demand levels, actions taken by major oil exporters and the resulting impacts on commodity prices; increased volatility or deterioration in the success rate of our exploration programs or in our ability to maintain production rates and replace reserves; reduced customer demand for our products due to environmental, regulatory, technological or other reasons; adverse foreign exchange movements; political and regulatory instability in the markets where we do business; the impact on our operations or market of health pandemics such as COVID-19 and related government responses; other natural hazards impacting our operations or markets; any other deterioration in our business, markets or prospects; any failure to obtain necessary regulatory approvals; any inability to service or refinance our outstanding debt or to access debt markets at acceptable prices; or adverse developments in the U.S. or global capital markets, credit markets or economies in general. For further discussion of factors that could cause one or more of these future events or results not to occur as implied by any forward-looking statement, see Item 1A. Risk Factors, which begins on page 15 of this Annual Report on Form 10-K. Murphy undertakes no duty to publicly update or revise any forward-looking statements, except as required by law.

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 L, Murphy makes use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions.

There were no outstanding crude oil derivative contracts as of December 31, 2022.

There were no derivative foreign exchange contracts in place as of December 31, 2022.

At December 31, 2022, long-term debt was $1,822.4 million. The fixed-rate notes have a weighted average coupon of 6.2%.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages 63 through 127 of this Form 10-K report.

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

None

PART II

Item 9A. CONTROLS AND PROCEDURES

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

Based on their evaluation, with the participation of the Company's management, as of December 31, 2022, 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, 2022. 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, 2022 and their report is included on page 66 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 2022 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. OTHER INFORMATION

None

Item 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Certain information regarding executive officers of the Company is included on page 29 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 10, 2023 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 www.murphyoilcorp.com. Stockholders may also obtain, free of charge, a copy of the Code of Ethical Conduct for Executive Management by writing to the Corporate Secretary at 9805 Katy Fwy, Suite G-200, Houston, TX 77024. Any future amendments to or waivers of the Company's Code of Ethical Conduct for Executive Management will be posted on the Company's Website.

Item 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 10, 2023 under the captions "Compensation Discussion and Analysis" and "How Are We Compensated" and in various compensation schedules.

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

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 10, 2023 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 10, 2023 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 10, 2023 under the caption "Audit Committee Report."

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

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

2. **Financial Statement Schedules**

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

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

Exhibit No.		Incorporated by Reference to the Indicated Filing by Murphy Oil Corporation
2.1	Purchase and sale agreement dated as of April 19, 2019 between LLOG Bluewater Holdings, LLC and LLOG Exploration Offshore, LLC, as seller, and Murphy Exploration & Production Company – USA, as purchaser.	Exhibit 2.1 to Form 8-K filed June 5, 2019
2.2	First Amendment to Purchase and Sale Agreement dated as of May 31, 2019 among Murphy Exploration & Production Company - USA, LLOG Exploration Offshore, L.L.C. and LLOG Bluewater Holdings, L.L.C.	Exhibit 2.2 to Form 8-K filed June 5, 2019
2.3	Contribution Agreement dated as of October 10, 2018 among Murphy Exploration & Production Company – USA, Petrobras America Inc. and MP Gulf of Mexico, LLC	Exhibit 2.1 to Form 10-K for the year ended December 31, 2018
2.4	Share Sale and Purchase Agreement between Canam Offshore Limited and PTTEP HK Offshore Limited for the sale and purchase of the entire issued share capital of Murphy Sarawak Oil Co., Ltd. and Murphy Sabah Oil Co., Ltd., dated March 21, 2019	Exhibit 10.3 to Form 10-Q filed May 2, 2019
3.1	Certificate of Incorporation of Murphy Oil Corporation, as amended effective May 11, 2005	Exhibit 3.1 to Form 10-K for the year ended December 31, 2010
3.2	By-Laws of Murphy Oil Corporation, as amended effective 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 for the year ended December 31, 2004
4.2	Supplemental Indenture dated as of May 4, 1999 between Murphy Oil Corporation and SunTrust Bank, Nashville, N.A., as trustee, relating to 7.05% Notes due 2029	Exhibit 4.2 to Form 10-K for the year ended December 31, 2004
4.3	Indenture dated as of May 18, 2012 between Murphy Oil Corporation and U.S. Bank National Association, as trustee	Exhibit 4.1 to Form 8-K filed May 18, 2012
4.4	First Supplemental Indenture dated as of May 18, 2012, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 4.00% Notes due 2022	Exhibit 4.2 to Form 8-K filed May 18, 2012
4.5	Second Supplemental Indenture dated as of November 30, 2012, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 5.125% Notes due 2042	Exhibit 4.1 to Form 8-K filed November 30, 2012
4.6	Third Supplemental Indenture dated as of August 17, 2016, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 6.875% Notes due 2024	Exhibit 4.1 to Form 8-K filed August 17, 2016
4.7	Fourth Supplemental Indenture dated as of August 18, 2017, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 5.75% Notes due 2025	Exhibit 4.1 to Form 8-K filed August 18, 2017
4.8	Fifth Supplemental Indenture dated as of November 27, 2019, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, and Wells Fargo Bank, National Association, as series trustee, relating to 5.875% Notes due 2027	Exhibit 4.2 to Form 8-K filed November 27, 2019
4.9	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934	Exhibit 4.9 to Form 10-K filed on February 27, 2020

4.10	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 files March 5, 2021
*10.1	New Credit Agreement dated as of November 17, 2022 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	
10.2	Murphy Oil Corporation Annual Incentive Plan	Exhibit 10.3 to Form 10-K filed on February 25, 2022
10.3	Murphy Oil Corporation 2012 Long-Term Incentive Plan	Exhibit A to definitive proxy statement filed March 29, 2012
10.4	Amendment to the Murphy Oil Corporation 2012 Long-Term Incentive Plan	Exhibit 10.8 to Form 10-K filed on February 27, 2020
10.5	Form of employee stock option (2012 Long-Term Incentive Plan)	Exhibit 99.1 to Form 10-K for the year ended December 31, 2013
10.6	Form of stock appreciation right (2012 Long-Term Incentive Plan)	Exhibit 99.3 to Form 10-Q filed May 7, 2014
10.7	Murphy Oil Corporation 2018 Long-Term Incentive Plan	Exhibit B to definitive proxy statement filed March 23, 2018
10.8	Amendment to the Murphy Oil Corporation 2018 Long-Term Incentive Plan	Exhibit 10.15 to Form 10-K filed on February 27, 2020
10.9	Form of employee performance-based restricted stock unit – stock settled grant agreement (2018 Long-Term Incentive Plan)	Exhibit 10.14 to Form 10-K for the year ended December 31, 2018
10.10	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 on February 27, 2020
10.11	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 for the year ended December 31, 2018
10.12	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 for the year ended December 31, 2018
10.13	Murphy Oil Corporation 2020 Long-Term Incentive Plan	Exhibit A to definitive proxy statement filed March 30, 2020
10.14	Form of employee performance-based restricted stock unit – stock settled grant agreement (2020 LTI Plan)	Exhibit 10.21 to Form 10-K filed on February 26, 2021
10.15	Form of employee time-based restricted stock unit – stock settled 3-year grant agreement (2020 LTI Plan)	Exhibit 10.22 to Form 10-K filed on February 26, 2021
10.16	Form of employee time-based restricted stock unit – stock settled 5-year grant agreement (2020 LTI Plan)	Exhibit 10.23 to Form 10-K filed on February 26, 2021
10.17	Form of employee time-based restricted stock unit – cash settled 3-year grant agreement (2020 LTI Plan)	Exhibit 10.24 to Form 10-K filed on February 26, 2021
10.18	Form of employee time-based restricted stock unit – cash settled 5-year grant agreement (2020 LTI Plan)	Exhibit 10.25 to Form 10-K filed on February 26, 2021
10.19	Murphy Oil Corporation 2018 Stock Plan for Non-Employee Directors	Exhibit A to definitive proxy statement filed March 23, 2018
10.20	First Amendment to the 2018 Stock Plan for Non-Employee Directors	Exhibit 10.1 to Form 8-K filed April 25, 2018
10.21	Second Amendment to the 2018 Stock Plan for Non-Employee Directors	Exhibit 10.24 to Form 10-K filed on February 27, 2020

10.22	Form of non-employee director restricted stock unit award – stock settled grant agreement (2018 NED Plan)	Exhibit 10.20 to Form 10-K for the year ended December 31, 2018
10.23	Murphy Oil Corporation 2021 Stock Plan for Non-Employee Directors	Exhibit A to definitive proxy statement filed March 26, 2021
10.24	Form of non-employee director restricted stock unit award – stock settled grant agreement (2021 NED Plan)	Exhibit 10.27 to Form 10-Q filed on August 5, 2021
10.25	Murphy Oil Corporation Non-Qualified Deferred Compensation Plan for Non-Employee Directors	Exhibit 10.6 to Form 10-K for the year ended December 31, 2015
10.26	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
10.27	Form of non-employee director restricted stock unit award – stock settled grant agreement (2018 NED Plan)	Exhibit 10.26 to Form 10-K filed on February 27, 2020
*10.28	First Amendment to the New Credit Agreement dated as of December 16, 2022 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	
*21.1	Subsidiaries of Murphy Oil Corporation	
*23.1	Consent of Independent Registered Public Accounting Firm	
*23.2	Consent of Ryder Scott Company, L.P.	
*23.3	Consent of McDaniel & Associates Consultants Ltd.	
*31.1	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
*31.2	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
*32.1	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	
*99.1	Ryder Scott reserves audit report for Eagle Ford Shale and Gulf of Mexico	
*99.2	Ryder Scott reserves audit report for MP GOM JV	
*99.3	McDaniel independent audit report for Canada Onshore and Offshore proved crude oil and natural gas reserves	
101.INS	Inline XBRL Instance 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).	

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MURPHY OIL CORPORATION

By	/s/ ROGER W. JENKINS	Date:	February 27, 2023
	Roger W. Jenkins, President		

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 27, 2023 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/ ROGER W. JENKINS	/s/ R. MADISON MURPHY
Roger W. Jenkins, President and Chief Executive Officer and Director (Principal Executive Officer)	R. Madison Murphy, Director
/s/ T. JAY COLLINS	/s/ JEFFREY W. NOLAN
T. Jay Collins, Director	Jeffrey W. Nolan, Director
/s/ STEVEN A. COSSE	/s/ ROBERT N. RYAN, JR.
Steven A. Cossé, Director	Robert N. Ryan, Jr., Director
/s/ LAWRENCE R. DICKERSON	/s/ NEAL E. SCHMALE
Lawrence R. Dickerson, Director	Neal E. Schmale, Director
/s/ MICHELLE A. EARLEY	/s/ LAURA A. SUGG
Michelle A. Earley, Director	Laura A. Sugg, Director
/s/ ELISABETH W. KELLER	/s/ THOMAS J. MIRELES
Elisabeth W. Keller, 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 64.

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

REPORT OF MANAGEMENT – INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management has conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the criteria set forth in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the results of this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2022.

KPMG LLP has performed an audit of the Company's internal control over financial reporting, and their opinion thereon can be found on page 66.

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, 2022 and 2021, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2022, 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, 2022, 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, 2023 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, 2022, the Company recorded depreciation, depletion, and amortization expense of $776.8 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, 2023

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, 2022, 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, 2022, 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, 2022 and 2021, 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, 2022, and the related notes and financial statement schedule II (collectively, the consolidated financial statements), and our report dated February 27, 2023 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, 2023

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31 (Thousands of dollars except share amounts)		2022	2021
ASSETS			
Current assets			
Cash and cash equivalents		**$ 491,963**	$ 521,184
Accounts receivable, net		**391,152**	258,150
Inventories	Note F	**54,513**	54,198
Prepaid expenses		**34,697**	31,925
Assets held for sale	Note E	**–**	15,453
Total current assets		**972,325**	880,910
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $12,489,970 in 2022 and $12,457,851 in 2021	Note D	**8,228,016**	8,127,852
Operating lease assets	Note U	**946,406**	881,389
Deferred income taxes	Note I	**117,889**	385,516
Deferred charges and other assets		**44,316**	29,273
Total assets		**$ 10,308,952**	$ 10,304,940
LIABILITIES AND EQUITY			
Current liabilities			
Current maturities of long-term debt, finance lease		**$ 687**	$ 654
Accounts payable		**543,786**	623,129
Income taxes payable		**26,544**	19,951
Other taxes payable		**22,819**	20,306
Operating lease liabilities		**220,413**	139,427
Other accrued liabilities		**443,585**	360,859
Total current liabilities		**1,257,834**	1,164,326
Long-term debt, including finance lease obligation	Note G	**1,822,452**	2,465,414
Asset retirement obligations	Note H	**817,268**	839,776
Deferred credits and other liabilities		**304,948**	570,574
Non-current operating lease liabilities	Note U	**742,654**	761,162
Deferred income taxes	Note I	**214,903**	182,892
Total liabilities		**$ 5,160,059**	$ 5,984,144
Equity			
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued		**$ –**	$ –
Common Stock, par $1.00, authorized 450,000,000 shares, issued 195,100,628 shares in 2022 and 195,100,628 shares in 2021		**195,101**	195,101
Capital in excess of par value		**893,578**	926,698
Retained earnings		**6,055,498**	5,218,670
Accumulated other comprehensive loss	Note O	**(534,686)**	(527,711)
Treasury stock		**(1,614,717)**	(1,655,447)
Murphy Shareholders' Equity		**4,994,774**	4,157,311
Noncontrolling interest		**154,119**	163,485
Total equity		**5,148,893**	4,320,796
Total liabilities and equity		**$ 10,308,952**	$ 10,304,940

See Notes to Consolidated Financial Statements, page 72.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

Years Ended December 31 (Thousands of dollars except per share amounts)	**2022**	2021	2020
Revenues and other income			
Revenue from production	**$ 4,038,451**	$ 2,801,215	$ 1,751,709
Sales of purchased natural gas	**181,689**	–	–
Total revenue from sales to customers	**4,220,140**	2,801,215	1,751,709
(Loss) Gain on derivative instruments	**(320,410)**	(525,850)	202,661
Gain on sale of assets and other income	**32,932**	23,916	12,971
Total revenues and other income	**3,932,662**	2,299,281	1,967,341
Costs and expenses			
Lease operating expenses	**679,342**	539,546	600,076
Severance and ad valorem taxes	**57,012**	41,212	28,526
Transportation, gathering and processing	**212,711**	187,028	172,399
Costs of purchased natural gas	**171,991**	–	–
Exploration expenses, including undeveloped lease amortization	**133,197**	69,044	86,479
Selling and general expenses	**131,121**	121,950	140,243
Restructuring expenses	**–**	–	49,994
Depreciation, depletion and amortization	**776,817**	795,105	987,239
Accretion of asset retirement obligations	**46,243**	46,613	42,136
Impairment of assets	**–**	196,296	1,206,284
Other operating expense	**137,518**	21,052	16,274
Total costs and expenses	**2,345,952**	2,017,846	3,329,650
Operating income (loss) from continuing operations	**1,586,710**	281,435	(1,362,309)
Other income (loss)			
Other income (expense)	**14,310**	(16,771)	(17,303)
Interest expense, net	**(150,759)**	(221,773)	(169,423)
Total other loss	**(136,449)**	(238,544)	(186,726)
Income (Loss) from continuing operations before income taxes	**1,450,261**	42,891	(1,549,035)
Income tax expense (benefit)	**309,464**	(5,862)	(293,741)
Income (Loss) from continuing operations	**1,140,797**	48,753	(1,255,294)
Loss from discontinued operations, net of income taxes	**(2,078)**	(1,225)	(7,151)
Net income (loss) including noncontrolling interest	**1,138,719**	47,528	(1,262,445)
Less: Net income (loss) attributable to noncontrolling interest	**173,672**	121,192	(113,668)
NET INCOME (LOSS) ATTRIBUTABLE TO MURPHY	**$ 965,047**	$ (73,664)	$ (1,148,777)
INCOME (LOSS) PER COMMON SHARE – BASIC			
Continuing operations	**$ 6.23**	$ (0.47)	$ (7.43)
Discontinued operations	**(0.01)**	(0.01)	(0.05)
Net income (loss)	**$ 6.22**	$ (0.48)	$ (7.48)
INCOME (LOSS) PER COMMON SHARE – DILUTED			
Continuing operations	**$ 6.14**	$ (0.47)	$ (7.43)
Discontinued operations	**(0.01)**	(0.01)	(0.05)
Net income (loss)	**$ 6.13**	$ (0.48)	$ (7.48)
Cash dividends per Common share	**$ 0.825**	$ 0.50	$ 0.625
Average Common shares outstanding (thousands)			
Basic	**155,277**	154,291	153,507
Diluted	**157,475**	154,291	153,507

See Notes to Consolidated Financial Statements, page 72.

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

Years Ended December 31 (Thousands of dollars)	**2022**	2021	2020
Net income (loss) including noncontrolling interest	**$ 1,138,719**	$ 47,528	$ (1,262,445)
Other comprehensive income (loss), net of tax			
Net (loss) gain from foreign currency translation	**(106,335)**	12,116	29,241
Retirement and postretirement benefit plans	**99,360**	59,816	(57,617)
Deferred loss on interest rate hedges reclassified to interest expense	**–**	1,690	1,204
Other comprehensive (loss) income	**(6,975)**	73,622	(27,172)
Comprehensive income (loss) including noncontrolling interest	**1,131,744**	121,150	(1,289,617)
Less: Comprehensive income (loss) attributable to noncontrolling interest	**173,672**	121,192	(113,668)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO MURPHY	**$ 958,072**	$ (42)	$ (1,175,949)

See Notes to Consolidated Financial Statements, page 72.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 (Thousands of dollars)	2022	2021	2020
Operating Activities			
Net income (loss) including noncontrolling interest	$ 1,138,719	$ 47,528	$ (1,262,445)
Adjustments to reconcile net income (loss) to net cash provided by continuing operations activities			
Depreciation, depletion and amortization	776,817	795,105	987,239
Deferred income tax expense (benefit)	286,079	(4,146)	(278,042)
Mark to market (gain) loss on derivative instruments	(214,788)	112,113	69,310
Mark to market loss (gain) on contingent consideration	78,285	63,147	(13,783)
Long-term non-cash compensation	89,246	63,382	46,558
Unsuccessful exploration well costs and previously suspended exploration costs	82,085	17,339	21,099
Accretion of asset retirement obligations	46,243	46,613	42,136
Amortization of undeveloped leases	13,300	18,925	26,743
Loss from discontinued operations	2,078	1,225	7,151
Gain from sale of assets	(17,899)	–	–
Impairment of assets	–	196,296	1,206,284
Noncash restructuring expense	–	–	17,565
Other operating activities, net	(34,193)	(53,821)	(35,080)
Net (increase) decrease in noncash working capital	(65,728)	118,457	(32,027)
Net cash provided by continuing operations activities	2,180,244	1,422,163	802,708
Investing Activities			
Property additions and dry hole costs [1]	(985,461)	(650,235)	(759,809)
Acquisition of oil and natural gas properties [1]	(128,538)	(20,244)	–
Property additions for King's Quay FPS	–	(17,734)	(112,961)
Proceeds from sales of property, plant and equipment	4,528	270,503	13,750
Net cash required by investing activities	(1,109,471)	(417,710)	(859,020)
Financing Activities			
Retirement of debt	(647,707)	(876,358)	(12,225)
Repayment of revolving credit facility	(400,000)	(365,000)	(250,000)
Borrowings on revolving credit facility	400,000	165,000	450,000
Distributions to noncontrolling interest	(183,038)	(137,517)	(43,673)
Cash dividends paid	(128,219)	(77,204)	(95,989)
Contingent consideration paid	(81,742)	–	–
Withholding tax on stock-based incentive awards	(17,631)	(5,209)	(7,094)
Issue costs of debt facility	(14,353)	–	–
Early redemption of debt cost	(8,295)	(39,335)	–
Capital lease obligation payments	(636)	(803)	(695)
Debt issuance, net of cost	–	541,913	(613)
Net cash (required) provided by financing activities	(1,081,621)	(794,513)	39,711
Cash Flows from Discontinued Operations			
Operating activities	(14,500)	–	–
Net cash (required) by discontinued operations	(14,500)	–	–
Cash from discontinued operations [2]	–	–	18,438
Effect of exchange rate changes on cash and cash equivalents	(3,873)	638	2,009
Net (decrease) increase in cash and cash equivalents	(29,221)	210,578	3,846
Cash and cash equivalents at beginning of period	521,184	310,606	306,760
Cash and cash equivalents at end of period	$ 491,963	$ 521,184	$ 310,606

[1] Certain prior-period amounts have been reclassified to conform to the current period presentation.
[2] Cash previously classified as held-for-sale

See Notes to Consolidated Financial Statements, page 72.

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

Years Ended December 31 (Thousands of dollars except number of shares)	**2022**	2021	2020
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	**$ –**	$ –	$ –
Common Stock – par $1.00, authorized 450,000,000 shares at December 31, 2022, 2021 and 2020, issued 195,100,628 at December 31, 2022, 2021 and 2020			
Balance at beginning of year	**195,101**	195,101	195,089
Exercise of stock options	**–**	–	12
Balance at end of year	**195,101**	195,101	195,101
Capital in Excess of Par Value			
Balance at beginning of year	**926,698**	941,692	949,445
Stock-based compensation	**25,242**	25,429	26,052
Restricted stock transactions and other	**(45,169)**	(38,749)	(33,649)
Exercise of stock options, including income tax benefits	**(13,193)**	(1,674)	(156)
Balance at end of year	**893,578**	926,698	941,692
Retained Earnings			
Balance at beginning of year	**5,218,670**	5,369,538	6,614,304
Net income (loss) for the year attributable to Murphy	**965,047**	(73,664)	(1,148,777)
Cash dividends	**(128,219)**	(77,204)	(95,989)
Balance at end of year	**6,055,498**	5,218,670	5,369,538
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(527,711)**	(601,333)	(574,161)
Foreign currency translation (losses) gains, net of income taxes	**(106,335)**	12,116	29,241
Retirement and postretirement benefit plans, net of income taxes	**99,360**	59,816	(57,617)
Deferred loss on interest rate hedge reclassified to interest expense, net of income taxes	**–**	1,690	1,204
Balance at end of year	**(534,686)**	(527,711)	(601,333)
Treasury Stock			
Balance at beginning of year	**(1,655,447)**	(1,690,661)	(1,717,217)
Awarded restricted stock, net of forfeitures	**32,297**	33,888	26,556
Exercise of stock options	**8,433**	1,326	–
Balance at end of year – 39,633,309 of Common Stock in 2022, 40,637,578 shares of Common Stock in 2021 and 41,502,003 shares of Common Stock in 2020	**(1,614,717)**	(1,655,447)	(1,690,661)
Murphy Shareholders' Equity	**4,994,774**	4,157,311	4,214,337
Noncontrolling Interest			
Balance at beginning of year	**163,485**	179,810	337,151
Net income (loss) attributable to noncontrolling interest	**173,672**	121,192	(113,668)
Distributions to noncontrolling interest owners	**(183,038)**	(137,517)	(43,673)
Balance at end of year	**154,119**	163,485	179,810
Total Equity	**$ 5,148,893**	$ 4,320,796	$ 4,394,147

See Notes to Consolidated Financial Statements, page 72.

These notes are an integral part of the consolidated financial statements of Murphy Oil Corporation and Consolidated Subsidiaries (Murphy/the Company) on pages 67-71 of the Form 10-K report.

Note A – Significant Accounting Polices

NATURE OF BUSINESS – Murphy Oil Corporation is an international oil and natural gas company that conducts its business through various operating subsidiaries. The Company primarily produces oil and natural gas in the United States and Canada and conducts oil and natural gas exploration activities worldwide. The Company sold its Malaysian assets in 2019 and they are reported as discontinued operations.

In connection with the LLOG Exploration Offshore L.L.C. and LLOG Bluewater Holdings, L.L.C., (LLOG) acquisition, we hold a 0.5% interest in two variable interest entities (VIEs), Delta House Oil and Gas Lateral LLC and Delta House Floating Production System (FPS) LLC (collectively Delta House). These VIEs have not been consolidated because we are not considered the primary beneficiary. These non-consolidated VIEs are not material to our financial position or results of operations. As of December 31, 2022, our maximum exposure to loss was $3.2 million (excluding operational impacts), which represents our net investment in Delta House. We have not provided any financial support to Delta House other than amounts previously required by our membership interest.

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

USE OF ESTIMATES – Preparing the financial statements of the Company in accordance with U.S. generally accepted accounting principles (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 liquids and natural gas are recorded when deliveries have occurred and legal ownership of the commodity transfers to the customer; the amount of revenue recognized reflects the consideration expected in exchange for those commodities. The Company measures revenue based on consideration specified in a contract and excludes taxes and other amounts collected on behalf of third parties. Revenues from the production of oil and natural gas properties in which Murphy shares in the undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Natural gas imbalances occur when the Company’s actual natural gas sales volumes differ from its proportional share of production from the well. The Company follows the sales method of accounting for these natural gas imbalances. The Company records a liability for natural gas imbalances when it has sold more than its working interest of natural gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2022 and 2021, 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, 2022 and 2021, 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.

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

PROPERTY, PLANT AND EQUIPMENT – The Company uses the successful efforts method to account for exploration and development expenditures. Leasehold acquisition costs are capitalized. If proved reserves are found on undeveloped property, the leasehold cost is transferred to proved properties. Costs of undeveloped leases associated with unproved properties are expensed over the life of the leases. Exploratory well costs are capitalized pending determination about whether proved reserves have been found. In certain cases, a determination of whether a drilled exploratory well has found proved reserves cannot be made immediately. This is generally due to the need for 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 recognized when there are indications that the estimated undiscounted future net cash flows of an asset are less than its carrying value. If an impairment occurs, the carrying value of the impaired asset is reduced to fair value. There were no impairments recognized in 2022. In 2021, the Company recognized pretax noncash impairment charges of $196.3 million to reduce the carrying values at select properties. In 2021, the Company recorded an impairment charge of $171.3 million for Terra Nova due to the status, including agreements with the partners, of operating and production plans and a $25.0 million impairment charge for assets reported as Assets held for sale in the Consolidated Balance Sheets. See also Note D for further discussion of impairment charges.

The Company records a liability for asset retirement obligations (ARO) equal to the fair value of the estimated cost to retire an asset. The ARO liability is initially recorded in the period in which the obligation meets the definition of a liability, which is generally when a well is drilled or the asset is placed in service. The ARO liability is estimated by the Company's engineers using existing regulatory requirements and anticipated future inflation rates. When the liability is initially recorded, the Company increases the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is increased over time to reflect the change in its present value and the capitalized cost is depreciated over the useful life of the related long-lived asset. The Company reevaluates the adequacy of its recorded ARO liability at least annually. Actual costs of asset retirements such as dismantling oil and natural gas production facilities and site restoration are charged against the related liability. 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 H 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. If a lease is present, further criteria is assessed to determine if the lease should be classified as an operating or finance lease. Operating leases are presented on the Consolidated Balance Sheet as "Operating lease assets" with the corresponding lease liabilities presented in "Operating lease liabilities" and "Non-current operating lease liabilities". Finance lease assets (related to Brunei) are presented on the Consolidated Balance Sheet within "Property, plant and equipment" with the corresponding liabilities presented in "Current maturities of long-term debt, 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 LOE, Selling and general expenses or capitalized in the Consolidated Financial Statements. Finance leases are depreciated with the relevant expenses recognized in "Depreciation, depletion and amortization" and "Interest expense, net" on the Consolidated Statement of Operations.

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

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

The accounting rules for income tax uncertainties permit recognition of income tax benefits only when they are more likely than not to be realized. The Company includes potential penalties and interest for uncertain income tax positions in income tax expense.

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

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

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

STOCK-BASED COMPENSATION

Equity-Settled Awards – The fair value of awarded stock options, restricted stock units and other stock-based compensation that are settled with Company shares is determined based on a combination of management assumptions and the market value of the Company's common stock. The Company uses a Monte Carlo valuation model to determine the fair value of performance-based restricted stock units (PSUs) that are equity settled and expense is recognized over the three-year vesting period. The fair value of time-lapse restricted stock units is determined based on the price of Company stock on the date of grant and expense is recognized over the vesting period.

The Company uses the Black-Scholes option pricing model for computing the fair value of equity-settled stock options. The primary assumptions made by management include the expected life of the stock option award and the expected volatility of Murphy's common stock price. The Company uses both historical data and current information to support its assumptions. Stock option expense is recognized on a straight-line basis over the respective vesting period of two or three years. The Company estimates the number of stock options and 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), cash-settled restricted stock units (CRSU) and phantom stock units 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 SAR, a Monte Carlo method for performance-based CRSU, and the period-end price of the Company's common stock for time-based CRSU and phantom units. When SARs are exercised and when CRSU and phantom units settle, the Company adjusts previously recorded expense to the final amounts paid out in cash for these awards. See Note J.

Note A – Significant Accounting Policies (Continued)

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

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

Note B – New Accounting Principles and Recent Accounting Pronouncements

Accounting Principles Adopted

Compensation-Retirement Benefits-Defined Benefit Plans-General. In August 2018, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2018-14 which modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. For public companies, the amendments in this ASU are effective for fiscal years ending after December 15, 2020, with early adoption permitted and is to be applied on a retrospective basis to all periods presented. The Company adopted the standard in the fourth quarter of 2020 and it did not have a material impact on its consolidated financial statements.

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

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

Income Taxes. In December 2019, the FASB issued ASU 2019-12, which removes certain exceptions for investments, intraperiod allocations and interim calculations and adds guidance to reduce complexity in accounting for income taxes. The amendments in this ASU are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. Implementation on a prospective or retrospective basis varies by specific topics within the ASU. The Company adopted this guidance in the first quarter of 2021 and it did not have a material impact on its consolidated financial statements.

Recent Accounting Pronouncements

None affecting the Company.

Note C – Revenue from Contracts with Customers

Nature of Goods and Services

The Company explores for and produces crude oil, natural gas and natural gas liquids (collectively oil and natural gas) in select basins around the globe. 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 and condensate, natural gas liquids and natural gas.

For operated oil and natural gas production where the non-operated working interest owner does not take-in-kind its proportionate interest in the produced commodity, the Company acts as an agent for the working interest owner and recognizes revenue only for its own share of the commingled production. The exception to this is the reporting of the noncontrolling interest in MP GOM as prescribed by U.S. GAAP.

U.S. - In the United States, the Company primarily produces oil and natural gas from fields in the Eagle Ford Shale area of South Texas and in the Gulf of Mexico. Revenue is generally recognized when oil and natural gas 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.

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)

For the years ended December 31, 2022, 2021 and 2020 the Company recognized $4,220.1 million, $2,801.2 million and $1,751.7 million, respectively, from contracts with customers for the sales of oil, natural gas liquids and natural gas.

			Years Ended December 31,		
(Thousands of dollars)			**2022**	2021	2020
Net crude oil and condensate revenue					
	United States	Onshore	**$ 856,219**	$ 626,136	$ 353,311
		Offshore[1]	**2,229,658**	1,478,993	940,265
	Canada	Onshore	**131,400**	119,799	93,591
		Offshore	**117,747**	92,741	71,495
	Other		**22,824**	4,924	1,806
Total crude oil and condensate revenue			**3,357,848**	2,322,593	1,460,468
Net natural gas liquids revenue					
	United States	Onshore	**64,015**	50,189	22,504
		Offshore[1]	**60,424**	44,411	19,749
	Canada	Onshore	**18,338**	16,375	8,921
Total natural gas liquids revenue			**142,777**	110,975	51,174
Net natural gas revenue					
	United States	Onshore	**64,037**	39,803	20,132
		Offshore[1]	**161,160**	81,944	49,300
	Canada	Onshore	**312,629**	245,900	170,635
Total natural gas revenue			**537,826**	367,647	240,067
Revenue from production			**4,038,451**	2,801,215	1,751,709
Sales of purchased natural gas					
	United States	Offshore	**204**	–	–
	Canada	Onshore	**181,485**	–	–
Total sales of purchased natural gas			**181,689**	–	–
Total revenue from sales to customers			**4,220,140**	2,801,215	1,751,709
(Loss) gain on crude contracts			**(320,410)**	(525,850)	202,661
Gain on sale of assets and other income			**32,932**	23,916	12,971
Total revenue and other income			**$ 3,932,662**	$ 2,299,281	$ 1,967,341

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

In 2022, the Company included additional line items on the face of the Consolidated Statements of Operations to report sales of purchased natural gas and costs of purchased natural gas. 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, 2022 and 2021, receivables from contracts with customers, net of royalties and associated payables, on the balance sheet from continuing operations, were $201.1 million and $169.8 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, 2022, 2021 or 2020.

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

Performance Obligations

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

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

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

As of December 31, 2022, the Company had the following sales contracts in place which are expected to generate revenue from sales to customers for a period of 12 months or more starting at the inception of the contract:

Current Long-Term Contracts Outstanding at December 31, 2022

Location	Commodity	End Date	Description	Approximate Volumes
U.S.	Natural Gas and NGL	Q1 2023	Deliveries from dedicated acreage in Eagle Ford	As produced
U.S.	Natural Gas and NGL	Q2 2023	Deliveries from dedicated acreage in Eagle Ford	As produced
Canada	Natural Gas	Q4 2023	Contracts to sell natural gas at USD index pricing	25 MMCFD
Canada	Natural Gas	Q4 2023	Contracts to sell natural gas at CAD fixed prices	38 MMCFD
Canada	Natural Gas	Q4 2024	Contracts to sell natural gas at USD index pricing	31 MMCFD
Canada	Natural Gas	Q4 2024	Contracts to sell natural gas at CAD fixed prices	100 MMCFD
Canada	Natural Gas	Q4 2024	Contracts to sell natural gas at CAD fixed prices	34 MMCFD
Canada	Natural Gas	Q4 2024	Contracts to sell natural gas at USD fixed pricing	15 MMCFD
Canada	Natural Gas	Q4 2026	Contracts to sell natural gas at USD index pricing	49 MMCFD
Canada	NGL	Q3 2023	Contracts to sell natural gas liquids at CAD pricing	952 BOEPD

Fixed price contracts 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, 2022		December 31, 2021	
(Thousands of dollars)	**Cost**	**Net**	Cost	Net
Exploration and production [1]	**$ 20,567,489**	**$ 8,204,463** [2]	$ 20,440,568	$ 8,098,396 [2]
Corporate and other	**150,498**	**23,553**	145,135	29,456
Property, plant and equipment	**$ 20,717,987**	**$ 8,228,016**	$ 20,585,703	$ 8,127,852
[1] Includes unproved mineral rights as follows:	**$ 476,981**	**$ 344,507**	$ 615,724	$ 131,107

[2] Includes $18,319 in 2022 and $22,543 in 2021 related to administrative assets and support equipment.

Divestments

During the third quarter of 2022, the Company completed the disposition of its 62.5% operated 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 asset retirement obligations 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 the Block CA-2 asset in Brunei for contingent consideration valued at approximately $8.7 million. No gain or loss was recorded related to this sale.

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

Acquisitions

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

Impairments

In 2021, the Company recorded an impairment charge of $171.3 million for Terra Nova due to the status, including agreements with the partners, of operating and production plans. Subsequently, the Company acquired an additional 7.525% working interest at Terra Nova following a commercial agreement to sanction an asset life extension project. The Company also recorded an impairment charge of $25.0 million for assets reported as Assets held for sale in the Consolidated Balance Sheet.

The following table reflects the recognized before tax impairments for the three years ended December 31, 2022.

	December 31,		
(Thousands of dollars)	**2022**	2021	2020
Canada	**$ –**	$ 171,296	$ –
Other Foreign	**–**	18,000	39,709
Corporate	**–**	7,000	14,060
U.S.	**–**	–	1,152,515
	$ –	$ 196,296	$ 1,206,284

Exploratory Wells

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

At December 31, 2022, 2021 and 2020, the Company had total capitalized drilling costs pending the determination of proved reserves of $171.9 million, $179.5 million and $181.6 million, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2022.

(Thousands of dollars)	**2022**	2021	2020
Beginning balance at January 1	**$ 179,481**	$ 181,616	$ 217,326
Additions pending the determination of proved reserves	**33,440**	16,725	3,999
Divestment	**(7,915)**	–	–
Capitalized exploration well costs charged to expense	**(33,146)**	(18,860)	(39,709)
Ending balance at December 31	**$ 171,860**	$ 179,481	$ 181,616

The capitalized well costs charged to expense during 2022 represent expenditures related to the Cutthroat-1 exploration well in block SEAL-M-428 in the Sergipe-Alagoas Basin offshore Brazil and Hoffe Park #1 (Mississippi Canyon 122) in the Gulf of Mexico.

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

	2022			2021			2020		
(Thousands of dollars)	**Amount**	**No. of Wells**	**No. of Projects**	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects
Aging of capitalized well costs:									
Zero to one year	**$ 15,527**	**2**	**2**	$ 13,273	3	3	$ –	–	–
One to two years	**13,307**	**2**	**2**	–	–	–	54,220	5	5
Two to three years	**–**	**–**	**–**	53,070	5	5	–	–	–
Three years or more	**143,026**	**5**	**4**	113,138	6	–	127,396	6	–
	$171,860	**9**	**8**	$ 179,481	14	8	$ 181,616	11	5

Of the $156.3 million of exploratory well costs capitalized more than one year at December 31, 2022, $96.3 million is in Vietnam, $37.1 million is in the U.S., $15.5 million is in Mexico, $4.7 million is in Canada and $2.7 million is 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 – Assets Held for Sale and Discontinued Operations

In September 2022, the Company sold its share of Brunei Block CA-2 to Petronas Carigali Brunei Ltd (see Note D for additional information). Additionally, in December 2022, the Company's former headquarters office building in El Dorado, Arkansas was sold. There were no remaining assets held for sale on the Consolidated Balance Sheet as of December 31, 2022. As of December 31, 2021, assets held for sale included the carrying value of the net property, plant and equipment of Brunei Block CA-2 and the Company's former headquarters office building in El Dorado, Arkansas.

The following table presents the carrying value of the major categories of assets and liabilities that are reflected as held for sale on the Company's Consolidated Balance Sheets at December 31, 2022 and 2021.

(Thousands of dollars)	**2022**	2021
Current assets		
Property, plant and equipment, net	**$ –**	$ 15,453
Total current assets associated with assets held for sale	**$ –**	$ 15,453

Note E - Assets Held for Sale and Discontinued Operations (Continued)

The Company has accounted for its former Malaysian exploration and production operations and its former U.K. and U.S. refining and marketing operations as discontinued operations for all periods presented. The results of operations associated with discontinued operations are presented in the following table.

(Thousands of dollars)	**2022**	2021	2020
Revenues	**$ –**	$ 795	$ 4,090
Costs and expenses			
Other costs and expenses	**2,078**	2,020	11,241
Loss from discontinued operations	**$ (2,078)**	$ (1,225)	$ (7,151)

Note F – Inventories

Inventories consisted of the following at December 31, 2022 and 2021:

	December 31,	
(*Thousands of dollars*)	**2022**	2021
Unsold crude oil	**$ 6,546**	$ 15,497
Materials and supplies	**47,967**	38,701
Inventories	**$ 54,513**	$ 54,198

Note G – Financing Arrangements and Debt

Long-term debt consisted of the following as of December 31, 2022 and 2021:

	December 31,	
(Thousands of dollars)	**2022**	**2021**
Notes payable		
6.875% notes, due August 2024	**$ –**	$ 242,428
5.75% notes, due August 2025	**248,675**	548,675
5.875% notes, due December 2027	**543,249**	543,249
6.375% notes, due July 2028	**451,934**	550,000
7.05% notes, due May 2029	**250,000**	250,000
6.125% notes, due December 2042 [1]	**339,761**	349,000
Total notes payable	**1,833,619**	2,483,352
Unamortized debt issuance cost and discount on notes payable	**(15,324)**	(22,773)
Total notes payable, net of unamortized discount	**1,818,295**	2,460,579
Capitalized lease obligation, due through March 2029 [1]	**4,844**	5,489
Total debt including current maturities	**1,823,139**	2,466,068
Current maturities	**(687)**	(654)
Total long-term debt	**$ 1,822,452**	$ 2,465,414

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

The amount of long-term debt repayable over each of the next five years and thereafter are as follows: nil in 2023, nil in 2024, $248.7 million in 2025, nil in 2026, $543.2 million in 2027 and $1.04 billion thereafter.

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

In November 2022, the Company entered into a $800 million revolving credit facility (RCF) and the previous revolving credit facility has been terminated effective November 2022. The RCF is a senior unsecured guaranteed facility which expires on November 17, 2027, unless the outstanding principal amount of the Company's 5.75%, 2025 (2025 Notes) as at February 15, 2025 exceeds $50.0 million, in which case, the RCF will expire on that date. 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 3.50x, 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 Prime Rate in effect on such day, (b) the NYFRB 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 and S&P, respectively. The Company incurred $14.4 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, 2022, the Company had no outstanding borrowings under the RCF and $57.6 million of outstanding letters of credit, which reduces the borrowing capacity of the RCF. At December 31, 2022, the interest rate in effect on borrowings under the facility would have been 6.96%. At December 31, 2022, the Company was in compliance with all covenants related to the RCF.

In November 2022, the Company redeemed $200.0 million aggregate principal amount of its 5.750% senior notes due 2025 (2025 Notes). The cost of debt extinguishment of $3.9 is included in "Interest expense, net" on the Consolidated Statement of Operations for the year ended December 31, 2022. The cash costs of $2.9 million are shown as a financing activity on the Consolidated Statement of Cash Flows for the year ended December 31, 2022.

In September and October 2022, the Company paid a total of $7.2 million to complete the open market repurchases of $9.2 million aggregate principal amount of its 6.125% senior notes due 2042 (2042 Notes). There were no additional cash costs related to the September and October 2022 debt extinguishment on the 2042 Notes for the year ended December 31, 2022.

In August 2022, the Company redeemed the remaining $42.4 million of its 6.875% senior notes due in 2024 (2024 Notes) and tendered $100.0 million and $98.1 million aggregate principal amount of its 2025 Notes and 6.375% senior notes due 2028 (2028 Notes), respectively. The total cost of the debt extinguishment of $4.0 million is included in "Interest expense, net" on the Consolidated Statement of Operations for the year ended December 31, 2022. The debt extinguishment on the 2025 and 2028 Notes had cash costs of $2.0 million and is shown as a financing activity on the Consolidated Statement of Cash Flows for the year ended December 31, 2022.

In June 2022, the Company redeemed $200.0 million aggregate principal amount of its 6.875% 2024 Notes. The cost of the debt extinguishment of $4.3 million is included in "Interest expense, net" on the Consolidated Statement of Operations for the year ended December 31, 2022. The cash costs of $3.4 million are shown as a financing activity on the Consolidated Statement of Cash Flows for the year ended December 31, 2022.

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

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

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

Note H – Asset Retirement Obligations

The asset retirement obligations liabilities (ARO) recognized by the Company at December 31, 2022 and 2021 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 2022 and 2021 is shown in the following table.

(Thousands of dollars)	**2022**	2021
Balance at beginning of year	**$ 971,893**	$ 849,956
Accretion	**46,243**	46,613
Liabilities incurred	**46,449**	54,439
Revisions of previous estimates	**(78,229)**	48,737
Liabilities settled	**(64,255)**	(27,824)
Liabilities associated with assets held for sale	**–**	263
Changes due to translation of foreign currencies	**(10,448)**	(291)
Balance at end of year	**911,653**	971,893
Current portion of liability at end of year [1]	**(94,385)**	(132,117)
Noncurrent portion of liability at end of year	**$ 817,268**	$ 839,776

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

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

Note I – Income Taxes

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

Note I – Income Taxes (Continued)

(Thousands of dollars)	**2022**	2021	2020
Income (loss) from continuing operations before income taxes			
United States	**$ 1,306,200**	$ 114,659	$ (1,407,598)
Foreign	**144,061**	(71,768)	(141,437)
Total	**$ 1,450,261**	$ 42,891	$ (1,549,035)
Income tax expense (benefit)			
U.S. Federal – Current	**$ –**	$ –	$ (10,627)
– Deferred	**234,749**	(1,480)	(249,253)
Total U.S. Federal	**234,749**	(1,480)	(259,880)
State	**9,010**	3,303	(8,413)
Foreign – Current	**18,134**	(5,158)	(5,072)
– Deferred	**47,571**	(2,527)	(20,376)
Total Foreign	**65,705**	(7,685)	(25,448)
Total	**$ 309,464**	$ (5,862)	$ (293,741)

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

(Thousands of dollars)	**2022**	2021	2020
Income tax expense (benefit) based on the U.S. statutory tax rate	**$ 304,555**	$ 9,007	$ (325,299)
Foreign income (loss) subject to foreign tax rates different than the U.S. statutory rate	**10,823**	13,270	(3,791)
State income taxes, net of federal benefit	**7,118**	2,500	(6,646)
U.S. tax benefit on certain foreign upstream investments	**–**	(8,916)	–
Change in deferred tax asset valuation allowance related to other foreign exploration expenditures	**24,748**	4,814	7,707
Tax effect on income attributable to noncontrolling interest	**(36,471)**	(25,450)	23,712
Other, net	**(1,309)**	(1,087)	10,576
Total	**$ 309,464**	$ (5,862)	$ (293,741)

Note I – Income Taxes (Continued)

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2022 and 2021 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	**2022**	2021
Deferred tax assets		
Property and leasehold costs	**$ 242,467**	$ 241,833
Liabilities for dismantlements	**31,017**	37,728
Postretirement and other employee benefits	**86,798**	114,790
U. S. net operating loss	**442,699**	577,531
Investment in partnership	**11,595**	39,396
Other deferred tax assets	**111,212**	135,838
Total gross deferred tax assets	**925,788**	1,147,116
Less valuation allowance	**(136,008)**	(111,259)
Net deferred tax assets	**789,780**	1,035,857
Deferred tax liabilities		
Deferred tax on undistributed foreign earnings	**(5,000)**	(5,000)
Accumulated depreciation, depletion and amortization	**(796,510)**	(786,846)
Other deferred tax liabilities	**(85,284)**	(41,387)
Total gross deferred tax liabilities	**(886,794)**	(833,233)
Net deferred tax (liabilities) assets	**$ (97,014)**	$ 202,624

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 $24.7 million in 2022, related all to non-U.S. items. Subsequent reductions of the valuation allowance are expected to be reported as reductions of tax expense assuming no offsetting change in the deferred tax asset.

The Company has an U.S. net operating loss of $2.1 billion at year-end 2022 with a corresponding deferred tax asset of $442.7 million. The Company believes the U.S. net operating loss being carried forward will more likely than not be utilized in future periods prior to expirations in 2036 and 2037.

Other Information

Currently the Company considers $100 million of Canada's past foreign earnings not permanently reinvested, with an accompanying $5 million liability. At December 31, 2021, $1.4 billion of past foreign earnings are considered permanently reinvested. The Company closely and routinely monitors these reinvestment positions considering underlying facts and circumstances pertinent to our business and the future operation of the Company.

Uncertain Income Tax Positions

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

(Thousands of dollars)	2022	2021	2020
Balance at January 1	$ 2,903	$ 2,832	$ 2,538
Additions for tax positions related to current year	77	71	3,042
Additions for tax positions related to prior year	948	–	–
Settlements with taxing authorities	–	–	(2,748)
Balance at December 31	$ 3,928	$ 2,903	$ 2,832

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, 2022, 2021 and 2020, respectively, for interest and penalties associated with uncertain tax positions. Income tax expense for the years ended December 31, 2022, 2021 and 2020 included net benefits for interest and penalties of nil, nil and $0.1 million, respectively, associated with uncertain tax positions.

In 2023, the Company currently expects to add between $0.1 million and $1.0 million to the provision for uncertain tax positions. Although existing liabilities could be reduced by settlement with taxing authorities or lapse due to statute of limitations, the Company believes that the changes in its unrecognized tax benefits due to these events will not have a material impact on the Consolidated Statement of Operations during 2023.

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, 2022, 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 – 2016. The Company has retained certain possible liabilities and rights to income tax receivables relating to Malaysia for the years prior to 2019. The Company believes current recorded liabilities are adequate.

Coronavirus Aid, Relief, and Economic Security Act

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

Note J – Incentive Plans

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

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

The 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, restricted stock units (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, 2.9 million shares are available for grant under the 2020 Long-Term Plan at December 31, 2022.

The Stock Plan for Non-Employee Directors (2021 NED Plan) permits the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company's Non-Employee Directors. The Company currently has outstanding incentive awards issued to Directors under the 2021 NED Plan and the 2018 Stock Plan for Non-Employee Directors (2018 NED Plan).

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

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

(Thousands of dollars)	**2022**	2021	2020
Compensation charged against income before income tax benefit	**$ 74,587**	$ 43,660	$ 24,812
Related income tax benefit recognized in income	**12,710**	7,196	2,672

As of December 31, 2022, there were $51.8 million in compensation costs to be expensed over approximately the next three years related to unvested share-based compensation arrangements granted by the Company. Employees receive net shares, after applicable withholding obligations, upon each stock option exercise and restricted stock award. Total income tax benefits realized from tax deductions related to stock option exercises under share-based payment arrangements were immaterial for the years ended December 31, 2022, 2021 and 2020.

Equity-Settled Awards

PERFORMANCE-BASED RESTRICTED STOCK UNITS – Performance-based restricted stock units (PSUs) to be settled in Common shares were granted in 2021 and 2022 under the 2020 Long-Term Plan and 2020 under the 2018 Long-Term Plan. Each grant will vest if the Company achieves specific performance objectives at the end of the designated performance period. Additional shares may be awarded if performance objectives are exceeded. If performance goals are not met, PSUs will not vest, but the recognized compensation cost associated with the stock award would not be reversed. For PSUs, the performance conditions are based on the Company's total shareholder return (80% weighting), compared to an industry peer group of companies, and the EBITDA divided by Average Capital Employed (ACE) metric (20% weighting) for PSU awards, over the performance period. During the performance period, PSUs are subject to transfer restrictions and are subject to forfeiture if a grantee terminates for reasons other than retirement, disability or death. Termination for these three reasons will lead to a pro rata award of amounts earned. No dividends are paid nor do voting rights exist on awards of PSUs prior to their settlement.

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

(Number of stock units)	**2022**	2021	2020
Outstanding at beginning of year	**2,670,756**	2,207,429	2,129,733
Granted	**595,700**	1,156,800	999,700
Vested and issued	**(654,177)**	(642,473)	(429,194)
Forfeited	**(463,812)**	(51,000)	(492,810)
Outstanding at end of year	**2,148,467**	2,670,756	2,207,429

The fair value of the equity-settled performance-based awards granted in each year was estimated on the date of grant using a Monte Carlo valuation model. Expected volatility was based on daily historical volatility of the Company's stock price compared to a peer group average over a three-year period. The risk-free interest rate is based on the yield curve of three-year U.S. Treasury bonds and the stock beta was calculated using three years of historical averages of daily stock data for Murphy and the peer group. The assumptions used in the valuation of the performance awards granted in 2022, 2021 and 2020 are presented in the following table.

	2022	2021	2020
Fair value per share at grant date	**$37.77 - $47.37**	$16.03	$21.51
Assumptions			
Expected volatility	**79.00% - 81.00%**	74.00%	39.00%
Risk-free interest rate	**1.39% - 2.85%**	0.18%	1.40%
Stock beta	**1.195 - 1.200**	1.169	0.864
Expected life	**3.0 years**	3.0 years	3.0 years

TIME-BASED RESTRICTED STOCK UNITS – Time-based RSUs have been granted to the Company's Non-Employee Directors (NED) under the 2018 NED Plan and 2021 NED Plan and to certain employees under the 2012 Long-Term Plan, 2018 Long-Term Plan and 2020 Long-Term Plan.

The fair value of the time-based restricted stock units awarded in 2022, 2021 and 2020 are presented in the following table.

Type of Plan	Valuation Methodology	**2022**	2021	2020
Non-Employee Directors[1]	Closing Stock Price at Grant Date	**$32.84**	$13.14 - $23.58	$22.59
Long-Term Incentive Plan[2]	Average Low/High Stock Price at Grant Date	**$29.80 - $49.86**	12.30	21.68

[1] Under the 2021 NED Plan, RSUs granted in 2021 are scheduled to vest in February 2022.

[2] The RSUs granted under the 2012 Plan will vest on the fifth anniversary of the date of grant. The RSUs granted under the 2018 and 2020 Long-Term Plan generally vest on the third anniversary of the date of grant.

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

(Number of share units)	**2022**	2021	2020
Outstanding at beginning of year	**1,451,438**	1,383,043	1,535,080
Granted	**416,492**	573,907	446,848
Vested and issued	**(462,418)**	(476,012)	(271,285)
Forfeited	**(177,720)**	(29,500)	(327,600)
Outstanding at end of year	**1,227,792**	1,451,438	1,383,043

STOCK OPTIONS – In 2017, the Company ceased the inclusion of stock options and SARs as a part of the long-term incentive compensation mix.

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 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 J – 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, 2019	2,920,410	43.93
Outstanding at Exercised	(47,000)	17.57
Outstanding at Forfeited	(825,010)	54.85
Outstanding at December 31, 2020	2,048,400	40.14
Exercised	(170,000)	17.57
Forfeited	(558,900)	52.61
Outstanding at December 31, 2021	1,319,500	37.77
Exercised	**(760,500)**	**23.29**
Forfeited	**(546,000)**	**49.65**
Outstanding at December 31, 2022	**13,000**	**28.51**
Exercisable at December 31, 2019	3,182,345	49.10
Exercisable at December 31, 2020	2,048,400	37.88
Exercisable at December 31, 2021	1,319,500	34.25
Exercisable at December 31, 2022	**13,000**	**28.51**

Additional information about stock options outstanding at December 31, 2022 is shown below.

	Options Outstanding			Options Exercisable		
Exercisable Price	No. of Options	Avg. Life Remaining in Years	Aggregate Intrinsic Value	No. of Options	Avg. Life Remaining in Years	Aggregate Intrinsic Value
28.51	13,000	1.1	$ 188,565	13,000	1.1	$ 188,565

The total intrinsic value of options exercised during 2022 was $10.9 million. Intrinsic value is the excess of the market price of stock at date of exercise over the exercise price received by the Company upon exercise. Aggregate intrinsic value is nil when the exercise price of the stock option exceeds the market price of the Company's common stock.

Cash-Settled Awards

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

SAR awards have terms similar to stock options. CPSU terms are similar to other performance-based restricted stock awards. CRSUs generally settle on the third anniversary of the date of grant. Phantom units generally settle three to five years from date of grant. Each award granted is settled, net of applicable income tax withholdings, in cash rather than with common shares. Total pre-tax expense recorded in the Consolidated Statements of Operations for all cash-settled stock-based awards was $49.3 million in 2022, $18.2 million in 2021 and $1.5 million in 2020.

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 $42.9 million, $29.0 million and $9.8 million was recorded in 2022, 2021 and 2020, respectively, for these plans.

Note K – Employee and Retiree Benefit Plans

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

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

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

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

The tables that follow provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets for the years ended December 31, 2022 and 2021 and a statement of the funded status as of December 31, 2022 and 2021.

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2022**	2021	**2022**	2021
Change in benefit obligation				
Obligation at January 1	**$ 939,380**	$ 981,467	**$ 96,133**	$ 108,378
Service cost	**7,875**	8,199	**968**	1,295
Interest cost	**22,747**	14,784	**2,211**	2,071
Participant contributions	**–**	–	**2,283**	2,648
Actuarial loss (gain)	**(238,407)**	(24,440)	**(29,533)**	(9,519)
Medicare Part D subsidy	**–**	–	**331**	300
Exchange rate changes	**(21,018)**	(1,764)	**(20)**	3
Benefits paid	**(47,504)**	(38,866)	**(4,694)**	(4,041)
Plan amendments	**–**	–	**–**	(5,002)
Obligation at December 31	**663,073**	939,380	**67,679**	96,133
Change in plan assets				
Fair value of plan assets at January 1	**611,302**	586,720	**–**	–
Actual return on plan assets	**(133,395)**	33,687	**–**	–
Employer contributions	**41,145**	31,607	**2,080**	1,093
Participant contributions	**–**	–	**2,283**	2,648
Medicare Part D subsidy	**–**	–	**331**	300
Exchange rate changes	**(20,604)**	(1,846)	**–**	–
Benefits paid	**(47,504)**	(38,866)	**(4,694)**	(4,041)
Fair value of plan assets at December 31	**450,944**	611,302	**–**	–
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	**3,584**	5,535	**–**	–
Other accrued liabilities	**(9,693)**	(10,144)	**(4,830)**	(4,867)
Deferred credits and other liabilities	**(206,020)**	(323,469)	**(62,849)**	(91,266)
Fund Status and net plan liability recognized at December 31	**$ (212,129)**	$ (328,078)	**$ (67,679)**	$ (96,133)

Note K – Employee and Retiree Benefit Plans (Continued)

At December 31, 2022, amounts included in "Accumulated other comprehensive loss" (AOCL) in the Consolidated Balance Sheets, before reduction for associated deferred income taxes, which have not been recognized in net periodic benefit expense are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
Net actuarial gain (loss)	$ (194,735)	$ 42,129
Prior service (credit) cost	(2,181)	4,470
	$ (196,916)	$ 46,599

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)	**2022**	2021	**2022**	2021	**2022**	2021
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	**$ 511,375**	$ 734,375	**$ 499,338**	$ 723,887	**$ 434,283**	$ 589,529
Unfunded nonqualified and directors' plans where accumulated benefit obligation exceeds fair value of plan assets	**141,917**	188,713	**139,634**	188,530	**–**	–
Unfunded other postretirement plans	**67,679**	96,133	**67,679**	96,133	**–**	–

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2022.

	Pension Benefits			Other Postretirement Benefits		
(Thousands of dollars)	**2022**	2021	2020	**2022**	2021	2020
Service cost	**$ 7,875**	$ 8,199	$ 7,967	**$ 968**	$ 1,295	$ 1,373
Interest cost	**22,747**	14,784	21,127	**2,211**	2,071	2,626
Expected return on plan assets	**(36,458)**	(19,222)	(24,316)	**–**	–	–
Amortization of prior service cost (credit)	**(684)**	591	640	**(532)**	–	–
Amortization of transitional (asset) liability	**231**	–	–	**(587)**	–	–
Recognized actuarial (gain) loss	**15,867**	20,565	22,828	**(28)**	(29)	(31)
Net periodic benefit expense	**9,578**	24,917	28,246	**2,032**	3,337	3,968
Termination benefits expense	**–**	–	8,434	**–**	–	–
Curtailment expense	**–**	–	586	**–**	–	(1,825)
Total net periodic benefit expense	**$ 9,578**	$ 24,917	$ 37,266	**$ 2,032**	$ 3,337	$ 2,143

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

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2022**	2021	**2022**	2021
Benefit obligation at December 31	**$ 122,915**	$ 225,117	**$ 107**	$ 526
Fair value of plan assets at December 31	**115,862**	218,746	**–**	–
Net plan liabilities recognized	**(7,053)**	(6,371)	**(107)**	(526)
Net periodic benefit expense (benefit)	**(5,322)**	598	**62**	64

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2022 and 2021 and net periodic benefit expense for 2022 and 2021.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,		Year		Year	
	2022	2021	**2022**	2021	**2022**	2021	**2022**	2021
Discount rate	**5.30 %**	2.54 %	**5.41 %**	2.86 %	**3.13 %**	2.24 %	**2.86 %**	2.51 %
Rate of compensation increase	**3.50 %**	3.04 %	**–**	–	**3.00 %**	3.04 %	**–**	–
Cash balance interest credit rate	**3.20 %**	1.89 %	**–**	–	**–**	–	**–**	–
Expected return on plan assets	**–**	–	**–**	–	**6.24 %**	4.25 %	**–**	–

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
2023	$ 45,104	$ 4,830
2024	46,418	4,858
2025	46,240	4,808
2026	47,003	4,820
2027	47,293	4,778
2028-2032	244,253	23,648

For purposes of measuring postretirement benefit obligations at December 31, 2022, the future annual rates of increase in the cost of health care were assumed to be 6.3% for 2023 decreasing each year to an ultimate rate of 4.0% in 2045 and thereafter.

During 2022, the Company made contributions of $34.0 million to its domestic defined benefit pension plans and $2.1 million to its domestic postretirement benefits plan. During 2023, the Company currently expects to make contributions of $31.1 million to its domestic defined benefit pension plans, $1.1 million to its foreign defined benefit pension plans and $4.8 million to its domestic postretirement benefits plan.

PLAN INVESTMENTS – Murphy Oil Corporation maintains an Investment Policy Statement (Statement) that establishes investment standards related to its funded domestic qualified retirement plan. Our investment strategy is to maximize long-term returns at an acceptable level of risk through broad diversification of plan assets in a variety of asset classes. Asset classes and target allocations are determined by our investment committee and include equities, fixed income and other investments, including hedge funds, real estate and cash equivalent securities. Investment managers are prohibited from investing in equity or fixed income securities issues by the Company. The majority of plan assets are highly liquid, providing flexibility for benefit payment requirements. The current target allocations for plan assets are 40-75% 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 December 31, 2022 and 2021 are presented in the following table.

	December 31,	
	2022	2021
Equity securities	**65.7 %**	60.9 %
Fixed income securities	**23.4 %**	21.7 %
Alternatives	**7.3 %**	13.5 %
Cash equivalents	**3.6 %**	3.9 %
	100.0 %	100.0 %

The Company's weighted average expected return on plan assets was 6.2% in 2022 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 6.2% expected return was comprised of the weighted average expected future equity securities return of 7.9% and a fixed income securities return of 4.6%. There is also an average expected investment expense of 0.6%. Over the last 10 years, the return on funded retirement plan assets has averaged 3.4%.

Note K – Employee and Retiree Benefit Plans (Continued)

At December 31, 2022, 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, 2022	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	$ 96,433	$ 96,433	$ –	$ –
U.S. small/midcap	64,421	64,421	–	–
Other alternative strategies	12,106	–	–	12,106
International equity	44,672	44,672	–	–
Emerging market equity	13,541	13,541	–	–
Fixed income securities:				
U.S. fixed income	85,190	35,661	49,528	–
International commingled trust fund	–	–	–	–
Emerging market mutual fund	–	–	–	–
Cash and equivalents	18,719	18,719	–	–
Total Domestic Plans	335,082	273,447	49,528	12,106
Foreign Plans				
Equity securities funds	23,877	–	23,877	–
Fixed income securities funds	30,727	–	30,727	–
Diversified pooled fund	31,246	–	31,246	–
Other	20,628	–	–	20,628
Cash and equivalents	9,384	–	9,384	–
Total Foreign Plans	115,862	–	95,234	20,628
Total	$ 450,944	$ 273,447	$ 144,763	$ 32,734

At December 31, 2021, the fair value measurements of retirement plan assets within the fair value hierarchy are included in the table that follows.

		Fair Value Measurements Using		
(Thousands of dollars)	Fair Value at December 31, 2021	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Plans				
Equity securities:				
U.S. core equity	$ 108,422	$ 108,422	$ –	$ –
U.S. small/midcap	73,222	73,222	–	–
Other alternative strategies	47,248	–	–	47,248
International equity	47,546	47,546	–	–
Emerging market equity	14,937	14,937	–	–
Fixed income securities:				
U.S. fixed income	92,231	36,888	55,343	–
Cash and equivalents	8,951	8,951	–	–
Total Domestic Plans	392,557	289,966	55,343	47,248
Foreign Plans				
Equity securities funds	73,642	–	73,642	–
Fixed income securities funds	40,610	–	40,610	–
Diversified pooled fund	54,317	–	54,317	–
Other	35,606	–	–	35,606
Cash and equivalents	14,570	–	14,570	–
Total Foreign Plans	218,745	–	183,139	35,606
Total	$ 611,302	$ 289,966	$ 238,482	$ 82,854

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

For domestic plans, U.S. core, small/midcap, international, emerging market equity securities and U.S. treasury securities are quoted prices in active markets. For commercial paper securities, the prices received generally utilize observable inputs in the pricing methodologies. Other alternative strategies funds consist of 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 also 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.

For foreign plans, the equity securities funds are comprised of U.K. and foreign equity funds valued daily based on fund net asset values. Fixed income securities funds are U.K. and Canadian securities valued daily at net asset values. The diversified pooled fund is valued daily at net asset value and contains a combination of U.K. and foreign equity securities.

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

(Thousands of dollars)	Hedged Funds and Other Alternative Strategies
Total at December 31, 2020	$ 97,685
Actual return on plan assets:	
Relating to assets held at the reporting date	5,206
Purchases, sales and settlements	(20,037)
Total at December 31, 2021	82,854
Actual return on plan assets:	
Relating to assets held at the reporting date	**(38,389)**
Purchases, sales and settlements	**(11,731)**
Total at December 31, 2022	**$ 32,734**

THRIFT PLANS – Most full-time U.S. employees of the Company may participate in thrift or similar savings plans by allotting up to a specified percentage of their base pay. The Company matches contributions at a stated percentage of each employee's allotment based on years of participation in the plans, with a maximum match of 6.0%. Amounts charged to expense for the Company's match to these plans were $6.0 million in 2022, $5.4 million in 2021 and $6.6 million in 2020.

Note L – Financial Instruments and Risk Management

DERIVATIVE INSTRUMENTS – Murphy uses derivative instruments, such as swaps and zero-cost commodity price collar contracts, to manage certain risks related to commodity prices, foreign currency exchange rates and interest rates. The use of derivative instruments for risk management is covered by operating policies and is closely monitored by the Company's senior management. The Company does not hold any derivatives for speculative purposes, and it does not use derivatives with leveraged or complex features. Derivative instruments are traded with creditworthy major financial institutions or over national exchanges such as the New York Mercantile Exchange (NYMEX). The Company has a risk management control system to monitor commodity price risks and any derivatives obtained to manage a portion of such risks. For accounting purposes, the Company has not designated commodity and foreign currency derivative contracts as hedges, and therefore, it recognizes all gains and losses on these derivative contracts in its Consolidated Statements of Operations.

Certain interest rate derivative contracts were previously accounted for as hedges and the gain or loss associated with recording the fair value of these contracts was deferred in AOCL and amortized to "Interest expense, net" over time. In 2021, the Company redeemed all of the remaining notes due 2022, which were associated with the interest rate derivative contracts, and expensed the remainder of the previously deferred loss on the interest rate swap of $2.1 million to "Interest expense, net" in the Consolidated Statement of Operations.

Commodity Price Risks

During 2022, the Company had crude oil swaps and collar contracts. Under the swaps contracts, which matured monthly, the Company paid the average monthly price in effect and received the fixed contract price on a notional amount of sales volume, thereby fixing the price for the commodity sold. Under the collar contracts, which also matured monthly, the Company purchased a put option and sold a call option with no net premiums paid to or received from counterparties. Upon maturity, collar contracts required payments by the Company if the NYMEX average closing price is above the ceiling price or payments to the Company if the NYMEX average closing price is below the floor price.

At December 31, 2022, the Company does not have any outstanding crude oil derivative contracts. At December 31, 2021, the Company had 20,000 barrels per day in NYMEX West Texas Intermediate (WTI) swap contracts at a price per barrel of $44.88 and 25,000 barrels per day in NYMEX WTI collar contracts with an average ceiling price per barrel of $75.20 and an average floor price per barrel of $63.24, both maturing ratably during 2022.

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, 2022 and 2021.

At December 31, 2022 and 2021, the fair value of derivative instruments not designated as hedging instruments are presented in the following table. See also Note P.

(Thousands of dollars)	**Asset (Liability) Derivatives Fair Value at December 31,**		
Type of Derivative Contract	**Balance Sheet Location**	**2022**	2021
Commodity swaps	**Accounts payable**	–	(239,882)
Commodity collars	**Accounts receivable**	–	4,280
	Accounts payable	–	(19,533)

For the years ended December 31, 2022, 2021 and 2020, the gains and losses recognized in the Consolidated Statements of Operations for derivative instruments not designated as hedging instruments are presented in the following table.

(Thousands of dollars)		**Gain (Loss) Year Ended December 31,**		
Type of Derivative Contract	**Statement of Operations Locations**	**2022**	2021	2020
Commodity swaps	**(Loss) Gain on derivative instruments**	**$ (160,690)**	$ (510,596)	$ 202,661
Commodity collars	**(Loss) Gain on derivative instruments**	**(159,721)**	(15,254)	–

Credit Risks

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

Note M – Earnings Per Share

Net income (loss) was used as the numerator in computing both basic and diluted income per Common share for each of the three years ended December 31, 2022. The following table reconciles the weighted-average shares outstanding used for these computations.

(Weighted-average shares)	**2022**	2021	2020
Basic method	**155,276,533**	154,290,741	153,507,109
Dilutive stock options and restricted stock units [1]	**2,198,305**	–	–
Diluted method	**157,474,838**	154,290,741	153,507,109

[1] Due to a net loss recognized by the Company for the year ended December 31, 2021 and 2020, no unvested stock awards were included in the computation of diluted earnings per share because the effect would have been antidilutive.

Note M - Earnings Per Share (Continued)

The following table reflects certain options to purchase shares of common stock that were outstanding during the three years ended December 31, 2022 but were not included in the computation of dilutive earnings per share because the incremental shares from the assumed conversion were antidilutive.

	2022	2021	2020
Antidilutive stock options excluded from diluted shares	**126,000**	1,420,992	2,246,532
Weighted average price of these options	**$49.65**	$35.30	$39.67

Note N – Other Financial Information

GAIN FROM FOREIGN CURRENCY TRANSACTIONS – Net gains (losses) from foreign currency transactions, including the effects of foreign currency contracts, included in the Consolidated Statements of Operations were $23.0 million in 2022, $1.0 million in 2021 and $(0.9) million in 2020.

Noncash operating working capital (increased) decreased during each of the three years ended December 31, 2022 as shown in the following table.

(Thousands of dollars)	**2022**	2021	2020
Net (increase) decrease in operating working capital, excluding cash and cash equivalents:			
(Increase) decrease in accounts receivable [1]	**$ (137,228)**	$ 8,056	$ 164,613
(Increase) decrease in inventories	**(1,534)**	12,809	5,953
(Increase) decrease in prepaid expenses	**(3,413)**	2,003	7,178
Increase (decrease) in accounts payable and accrued liabilities [1]	**69,854**	95,166	(208,740)
Increase (decrease) in income taxes payable	**6,593**	423	(1,031)
Net (increase) decrease in noncash operating working capital	**$ (65,728)**	$ 118,457	$ (32,027)
Supplementary disclosures:			
Cash income taxes paid, net of refunds	**$ 24,853**	$ 2,138	$ (44,175)
Interest paid, net of amounts capitalized of $16.3 million in 2022, $16.1 million in 2021 and $8.0 million in 2020	**149,957**	165,699	191,561
Non-cash investing activities:			
Asset retirement costs capitalized	**$ (21,147)**	$ 54,439	$ 14,736
(Increase) decrease in capital expenditure accrual	**(31,397)**	9,788	84,645

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

Note O – Accumulated Other Comprehensive Loss

The components of AOCL on the Consolidated Balance Sheets at December 31, 2022 and December 31, 2021 and the changes during 2022 and 2021 are presented net of taxes in the following table.

(Thousands of dollars)	Foreign Currency Translation Gains (Losses)	Retirement and Postretirement Benefit Plan Adjustments	Deferred Loss on Interest Rate Derivative Hedges	Total
Balance at December 31, 2020	$ (324,011)	$ (275,632)	$ (1,690)	$ (601,333)
2021 components of other comprehensive income (loss):				
Before reclassifications to income	12,116	40,095	–	52,211
Reclassifications to income	–	19,721 [1]	1,690 [2]	21,411
Net other comprehensive income	12,116	59,816	1,690	73,622
Balance at December 31, 2021	(311,895)	(215,816)	–	(527,711)
2022 components of other comprehensive income (loss):				
Before reclassifications to income	**(106,335)**	**87,362**	**–**	**(18,973)**
Reclassifications to income	**–**	**11,998** [1]	**–** [2]	**11,998**
Net other comprehensive income (loss)	**(106,335)**	**99,360**	**–**	**(6,975)**
Balance at December 31, 2022	**$ (418,230)**	**$ (116,456)**	**$ –**	**$ (534,686)**

[1] Reclassifications before taxes of $15.3 million and $23.5 million are included in the computation of net periodic benefit expense in 2022 and 2021, respectively. See Note K for additional information. Related income taxes of $3.3 million and $3.8 million are included in income tax expense in 2022 and 2021, respectively.
[2] Reclassifications before taxes of nil and $2.1 million are included in Interest expense in 2022 and 2021, respectively. Related income taxes of nil and $0.5 million are included in Income tax expense in 2022 and 2021, respectively. See Note L for additional information.

Note P – Assets and Liabilities Measured at Fair Value

Fair Values – Recurring

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

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

The fair value measurements for these assets and liabilities at December 31, 2022 and 2021 are presented in the following table.

	December 31, 2022				December 31, 2021			
(Thousands of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Assets:								
Commodity collars	**$ –**	**$ –**	**$ –**	**$ –**	$ –	$ 4,280	$ –	$ 4,280
Liabilities:								
Nonqualified employee savings plan	**$15,135**	**$ –**	**$ –**	**$15,135**	$16,962	$ –	$ –	$ 16,962
Commodity collars	**–**	**–**	**–**	**–**	–	19,533	–	19,533
Contingent consideration	**–**	**–**	**–**	**–**	–	–	196,151	196,151
Commodity swaps	**–**	**–**	**–**	**–**	–	239,882	–	239,882
	$15,135	**$ –**	**$ –**	**$15,135**	$16,962	$259,415	$196,151	$472,528

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.

As of December 31, 2022, there were no outstanding commodity (WTI crude oil) swaps and collars contracts subject to fair value measurement. The liabilities associated with these contracts have been finalized as of December 31, 2022 and were based on realized WTI pricing. The commodity swaps and collars liability as of December 31, 2022 was $19.6 million and $2.3 million, respectively, and recorded as "Accounts payable" in the Consolidated Balance Sheet. The fair value of the commodity (WTI crude oil) swaps in 2021 was based on active market quotes for WTI crude oil. The fair value of commodity (WTI crude oil) collars in 2021 was determined using an option pricing model based on inputs that include (i) the contracted notional volumes, (ii) independent active market price quotes, (iii) the applicable estimated risk-free rate yield curve and (iv) the implied rate of volatility inherent in the collar contract. The before tax income effect of changes in fair value of crude oil derivative contracts is recorded in "(Loss) Gain on derivative instruments" in the Consolidated Statements of Operations.

In 2019, the Company acquired strategic deepwater Gulf of Mexico assets from LLOG Exploration Offshore L.L.C. and LLOG Bluewater Holdings, L.L.C., (LLOG). Under the terms of the transaction, in addition to the consideration paid, Murphy has an obligation to pay additional contingent consideration of up to $200 million in the event that certain revenue thresholds are exceeded between 2019 and 2022; and $50 million following first oil from certain development projects. The revenue threshold was not exceeded for 2019 or 2020; however, the threshold was met in 2021 and 2022.

In 2018, the Company, through a subsidiary, acquired Gulf of Mexico producing assets from Petrobras America Inc. (PAI), a subsidiary of Petróleo Brasileiro S.A. Under the terms of the transaction, in addition to the consideration paid, Murphy has an obligation to pay additional contingent consideration of up to $150 million if certain price and production thresholds are exceeded beginning in 2019 through 2025; and $50 million carry for PAI development costs in the St. Malo Field if certain enhanced oil recovery projects are undertaken. The price and production thresholds were not exceeded for 2019 and 2020; however, the thresholds were met in 2021 and 2022. As of December 31, 2021, Murphy had completely funded the carried interest.

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, is no longer subject to fair value measurement. The liability is 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 (expense)" in the Consolidated Statements of Operations. For 2021 the Company's contingent consideration liabilities with PAI and LLOG were measured at fair value on a recurring basis and were categorized as Level 3 in the fair value hierarchy as at

December 31, 2021. The contingent consideration liabilities were valued using a Monte Carlo simulation model, which used the following assumptions as of December 31, 2021: (i) the remaining expected life of 1 year for LLOG and 4 years for PAI, (ii) West Texas Intermediate forward strip pricing with historical volatility of 9.9% and (iii) a risk-free interest rate of 1.49%.

The 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, 2022 and 2021.

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2022 and 2021. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, trade accounts payable and accrued expenses, all of which had fair values approximating carrying amounts. The fair value of current and long-term debt was estimated based on rates offered to the Company at that time for debt of the same maturities. The Company has off-balance sheet exposures relating to certain letters of credit. The fair value of these, which represents fees associated with obtaining the instruments, was nominal.

	December 31,			
	2022		2021	
(*Thousands of dollars*)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial assets (liabilities):				
Current and long-term debt	**$ (1,823,139)**	**$ (1,668,216)**	$ (2,466,068)	$ (2,666,773)

Fair Values – Nonrecurring

There was no impairment expense incurred in 2022. In 2021, an impairment charge of $171.3 million was triggered when the operator at Terra Nova provided notice of abandonment in the first quarter of 2021, before a commercial resolution in the third quarter of 2021 led Murphy to acquire an additional 7.525% in a commercial settlement with the other partners. The commercial resolution would have meant the Terra Nova impairment charge was not required. In the fourth quarter of 2021, a further impairment charge of $25 million was recorded on non-core assets.

The fair value information associated with the 2021 impaired properties is presented in the following table.

	Year Ended December 31,				
	Fair Value			Net Book Value Prior to Impairment	Total Pretax Impairment
(*Thousands of dollars*)	Level 1	Level 2	Level 3		
2021					
Assets:					
Impaired proved properties					
U.S. Offshore	$ –	$ –	$ 156,185	$ 327,481	$ 171,296
Other Foreign	–	–	25,739	43,739	18,000
Corporate	–	–	36,994	43,994	7,000

Note Q – Commitments

The Company has operating, production handling and transportation service agreements for oil and/or natural gas operations in the U.S. and Canada Onshore. The U.S. Onshore and Gulf of Mexico transportation contracts require minimum monthly payments through 2045, while the Canada Onshore processing 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 $295.4 million in 2023, $118.8 million in 2024, $91.2 million in 2025, $82.2 million in 2026 and $69.0 million in 2027. 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 $216.4 million in 2022, $151.8 million in 2021 and $107.6 million in 2020.

Commitments for capital expenditures were approximately $282.4 million at December 31, 2022, including $200.9 million for costs to develop deepwater U.S. Gulf of Mexico fields, $46.6 million for Eagle Ford Shale, $33.8 million for Canada and $1.1 million for Other Foreign.

Note R – Environmental and Other Contingencies

The Company's operations and earnings have been and may be affected by various forms of governmental action both in the United States and throughout the world. Examples of such governmental action include, but are by no means limited to: tax legislation changes, including tax rate changes, and retroactive tax claims; royalty and revenue sharing increases; import and export controls; price controls; currency controls; allocation of supplies of crude oil and petroleum products and other goods; expropriation of property; restrictions and preferences affecting the issuance of oil and natural gas or mineral leases; restrictions on drilling and/or production; laws, 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 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.

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 environment 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, the Inflation Reduction Act of 2022 contains provisions that impose fees for excess methane emissions from petroleum and natural gas facilities. In addition, there have been a number of executive orders issued that address climate change, including creation of climate-related task forces, directives to federal agencies to procure carbon-free electricity, and a goal of a carbon pollution-free power sector by 2035 and a net-zero emissions U.S. economy by 2050. 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. The Paris Agreement entered into force in November 2016. Although the U.S. officially withdrew from the Paris Agreement on November 4, 2020, the U.S. has since rejoined the Paris Agreement, which became effective for the U.S. on February 19, 2021.

The Company currently owns or leases, and has in the past owned or leased, properties at which hazardous substances have been or are being handled. Hazardous substances may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under Murphy's control. Under existing laws, the Company could be required to investigate, remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to investigate and clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. Certain of these historical properties are in various stages of negotiation, investigation, and/or cleanup, and the Company is investigating the extent of any such liability and the availability of applicable defenses. The Company has retained certain liabilities related to environmental matters at formerly owned U.S. refineries that were sold in 2011. The Company also obtained insurance covering certain levels of environmental exposures related to past operations of these refineries. Murphy USA Inc. has retained any environmental exposure associated with Murphy's former U.S. marketing operations that were spun-off in August 2013. The Company believes costs related to these sites will not have a material adverse effect on Murphy's net income, financial condition or liquidity in a future period.

There is the possibility that environmental expenditures could be required at currently unidentified sites, and additional expenditures could be required at known sites. However, based on information currently available to the Company, the amount of future investigation and remediation costs incurred at known or currently unidentified sites is not expected to have a material adverse effect on the Company's future net income, cash flows or liquidity.

LEGAL MATTERS – Murphy and its subsidiaries are engaged in a number of other legal proceedings (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 S – Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2022 is shown below.

(*Number of shares outstanding*)	**2022**	2021	2020
Beginning of year	**154,463,050**	153,598,625	152,935,361
Stock options exercised [1]	**181,655**	32,554	11,359
Restricted stock awards [1]	**822,614**	831,871	651,905
End of year	**155,467,319**	154,463,050	153,598,625

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

Note T – Business Segments

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

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.

	2022	2021	2020
Chevron Corporation	**19 %**	30 %	24 %
ExxonMobil Corporation	**12 %**	N/A	N/A
Phillips 66	**N/A**	N/A	18 %

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.

Note T - Business Segments (Continued)

No assets were held for sale as of December 31, 2022. Assets held for sale as of December 31, 2021 include the net property, plant and equipment of the Brunei Block CA-2 and the Company's office building in El Dorado, Arkansas (see Note E). The U.K. and Malaysian operations 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 contracts), interest expense and unallocated overhead, are shown in the tables to reconcile the business segments to consolidated totals.

	Exploration and Production						
(Millions of dollars)	United States [1]	Canada	Other	Total E&P	Corporate and Other	Discontinued Operations	Consolidated Total
Year ended December 31, 2022							
Segment income (loss) - including NCI [1]	**$1,521.9**	**$ 134.2**	**$ (77.0)**	**$1,579.1**	**$ (438.3)**	**$ (2.1)**	**$ 1,138.7**
Revenues from external customers	**3,461.2**	**762.9**	**23.0**	**4,247.1**	**(314.4)**	**–**	**3,932.7**
Interest and other income (loss)	**(6.6)**	**(1.9)**	**(0.5)**	**(9.0)**	**23.3**	**–**	**14.3**
Interest expense, net of capitalization	**(0.1)**	**–**	**(0.3)**	**(0.4)**	**(150.4)**	**–**	**(150.8)**
Income tax expense (benefit)	**370.8**	**43.6**	**2.9**	**417.3**	**(107.8)**	**–**	**309.5**
Significant noncash charges (credits)							
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**
Amortization of undeveloped leases	**8.7**	**0.2**	**4.4**	**13.3**	**–**	**–**	**13.3**
Deferred and noncurrent income taxes	**362.7**	**34.8**	**0.6**	**398.1**	**(112.0)**	**–**	**286.1**
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**	**1,034.6**	**0.8**	**10,309.0**
Year ended December 31, 2021							
Segment income (loss) - including NCI [1]	$ 766.3	(16.1)	(33.5)	716.7	$ (668.0)	(1.2)	47.5
Revenues from external customers	2,337.5	476.3	4.9	2,818.7	(519.4)	–	2,299.3
Interest and other income (loss)	(11.6)	(1.9)	3.2	(10.3)	(6.5)	–	(16.8)
Interest expense, net of capitalization	–	–	(0.2)	(0.2)	(221.6)	–	(221.8)
Income tax expense (benefit)	183.9	(1.7)	(9.5)	172.7	(178.6)	–	(5.9)
Significant noncash charges (credits)							
Impairment of assets	–	171.3	18.0	189.3	7.0	–	196.3
Depreciation, depletion and amortization	616.5	163.8	1.8	782.1	13.0	–	795.1
Accretion of asset retirement obligations	36.9	9.7	–	46.6	–	–	46.6
Amortization of undeveloped leases	11.1	0.2	7.6	18.9	–	–	18.9
Deferred and noncurrent income taxes	176.3	(1.9)	(8.0)	166.4	(170.5)	–	(4.1)
Additions to property, plant, equipment	519.5	52.7	13.1	585.3	–	–	585.3
Total assets at year-end	6,591.6	2,231.9	259.8	9,083.3	1,220.8	0.8	10,304.9

(Millions of dollars)	Exploration and Production: United States [1]	Exploration and Production: Canada	Exploration and Production: Other	Exploration and Production: Total E&P	Corporate and Other	Discontinued Operations	Consolidated Total
Year ended December 31, 2020							
Segment income (loss) - including NCI [1]	$(1,014.3)	$ (35.0)	$ (85.6)	$(1,134.9)	$ (120.3)	$ (7.2)	$ (1,262.4)
Revenues from external customers	1,411.8	345.8	1.8	1,759.4	207.9	–	1,967.3
Interest and other income (loss)	(9.9)	0.8	0.8	(8.2)	(9.1)	–	(17.3)
Interest expense, net of capitalization	–	(0.5)	(0.4)	(0.9)	(168.5)	–	(169.4)
Income tax expense (benefit)	(244.2)	(21.4)	2.1	(263.5)	(30.2)	–	(293.7)
Significant noncash charges (credits)							
Impairment of assets	1,152.5	–	39.7	1,192.2	14.1	–	1,206.3
Depreciation, depletion and amortization	749.4	213.2	2.3	964.9	22.3	–	987.2
Accretion of asset retirement obligations	36.6	5.5	–	42.1	–	–	42.1
Amortization of undeveloped leases	17.2	0.4	9.1	26.7	–	–	26.7
Deferred and noncurrent income taxes	(244.2)	(10.6)	1.9	(252.9)	(25.1)	–	(278.0)
Additions to property, plant, equipment	623.1	118.3	15.2	756.6	–	–	756.6
Total assets at year-end	6,915.5	2,404.1	267.7	9,587.3	1,032.9	0.7	10,620.9

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

Geographic Information

(Millions of dollars)	Certain long-lived assets at December 31 [1]: United States	Canada	Other	**Total**
2022	**$ 6,562.8**	**$ 1,499.1**	**$ 166.1**	**$ 8,228.0**
2021	6,371.4	1,566.9	189.6	8,127.9
2020	6,395.7	1,702.5	170.8	8,269.0

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

Note U – Leases

Nature of Leases

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

Related Expenses

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

(Thousands of dollars)	**Financial Statement Category**	**Year Ended December 31, 2022**	**2021**
Operating lease [1,2]	Lease operating expenses	**$ 217,038**	$ 198,189
Operating lease [2]	Transportation, gathering and processing	**39,669**	39,396
Operating lease [2]	Selling and general expense	**8,003**	9,019
Operating lease [2]	Other operating expense	**510**	7,480
Operating lease [2]	Exploration expenses	**10,019**	902
Operating lease [2]	Property, plant and equipment	**196,829**	81,924
Operating lease [2]	Asset retirement obligations	**11,190**	11,103
Finance lease			
Amortization of asset	Depreciation, depletion and amortization	**5,481**	1,173
Interest on lease liabilities	Interest expense, net	**254**	228
Sublease income	Other income	**(1,296)**	(2,482)
Net lease expense		**$ 487,697**	$ 346,932

[1] *Variable lease expenses.* For the years ended December 31, 2022 and 2021, includes variable lease expenses of $32.2 million and $25.8 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, 2022, includes $62.8 million in LOE, $31.5 million for “Transportation, gathering and processing”, $8.8 million for “Exploration expenses, including undeveloped lease amortization”, $0.7 million in “Selling and general expenses”, $0.1 million in “Other operating expense”, $125.4 million in “Property, plant and equipment, net” and $11.2 million in “Asset retirement obligations” relating to short-term leases due within 12 months. Expenses primarily relate to drilling rigs and other oil and natural gas field equipment. For the year ended December 31, 2021, includes $56.9 million in LOE, $30.2 million in “Transportation, gathering and processing”, $2.1 million in “Selling and general expenses", $0.2 million in “Other operating expense”, $28.9 million in “Property, plant and equipment, net” and $11.1 million in “Asset retirement obligations” relating to short-term leases due within 12 months. Expenses primarily relate to drilling rigs and other oil and natural gas field equipment.

Maturity of Lease Liabilities

(Thousands of dollars)	**Operating Leases**	**Finance Leases**	**Total**
2023	$ 270,868	$ 1,068	$ 271,936
2024	241,455	1,069	242,524
2025	79,974	1,068	81,042
2026	61,534	1,069	62,603
2027	59,964	1,069	61,033
Remaining	548,118	1,336	549,454
Total future minimum lease payments	1,261,913	6,679	1,268,592
Less imputed interest	(298,846)	(1,835)	(300,681)
Present value of lease liabilities [1]	**$ 963,067**	**$ 4,844**	**$ 967,911**

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

Lease Term and Discount Rate

	December 31, 2022	December 31, 2021
Weighted average remaining lease term:		
Operating leases	**9 years**	12 years
Finance leases	**6 years**	7 years
Weighted average discount rate:		
Operating leases	**5.9 %**	5.7 %
Finance leases	**4.7 %**	4.7 %

Other Information

	Year Ended December 31,	
(Thousands of dollars)	2022	2021
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	**$ 212,061**	$ 194,412
Operating cash flows from finance leases	**254**	228
Financing cash flows from finance leases	**636**	803
Right-of-use assets obtained in exchange for lease liabilities:		
Operating leases [1]	**$ 262,669**	$ 95,500

[1] For the year ended December 31, 2022, ROU assets obtained in exchange for lease liabilities primarily includes $254.0 million related to an extension of the lease of an existing offshore drilling rig by 24 months. December 31, 2021, includes $90.3 million related to an offshore drilling rig with a lease term of 16 months.

Note V – Restructuring Charges

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

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

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

The liability associated with the Company's restructuring activities at December 31, 2022 and 2021 is nil and $2.2 million, respectively, which is reflected in "Other accrued liabilities" on the Consolidated Balance Sheets.

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

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

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

Reserves of crude oil, condensate, natural gas liquids and natural gas are estimated by the Company's or independent engineers and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reserve estimates and future cash flows are based on the average market prices for sales of oil and natural gas on the first calendar day of each month during the year. The average prices used for 2022 were $93.67 per barrel for NYMEX crude oil (WTI) and $6.36 per MCF for natural gas (Henry Hub). The average prices used for 2021 were $66.56 per barrel for NYMEX crude oil (WTI) and $3.60 per MCF for natural gas (Henry Hub). The average prices used for 2020 were $39.57 per barrel for NYMEX crude oil (WTI) and $1.98 per MCF for natural gas (Henry Hub). 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 natural gas liquids.

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

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

GAAP requires calculation of future net cash flows using a 10% annual discount factor, an unweighted average of oil and natural gas prices in effect at the beginning of each month of the year, and year-end costs and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates.

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

Schedule 7 also presents the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 2022.

Schedule 1 – Summary of Total Proved Equivalent Reserves Based on Average Prices for 2019 – 2022

	Equivalents			
(Millions of barrels of oil equivalent)	Total	United States	Canada	Other
Proved developed and undeveloped reserves:				
December 31, 2019	825.0	500.1	324.1	0.8
Revisions of previous estimates	(194.7)	(146.6)	(47.3)	(0.8)
Extensions and discoveries	150.3	19.5	130.7	–
Sales of properties	(1.7)	(1.7)	–	–
Production	(63.9)	(42.8)	(21.1)	–
December 31, 2020	714.9	328.5	386.4	–
Revisions of previous estimates	(52.9)	35.6	(89.3)	0.8
Extensions and discoveries	109.4	18.2	91.3	–
Purchases of properties	7.4	1.6	5.8	–
Sales of properties	(0.7)	–	(0.7)	–
Production	(61.1)	(40.4)	(20.6)	(0.1)
December 31, 2021	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**	**–**	**–**
Sales of properties	**(4.4)**	**(4.4)**	**–**	**–**
Production	**(63.9)**	**(41.9)**	**(21.7)**	**(0.3)**
December 31, 2022 [1]	**715.4**	**357.0**	**357.8**	**0.6**
Proved developed reserves:				
December 31, 2019	472.3	273.4	198.1	0.8
December 31, 2020	410.8	230.3	180.5	–
December 31, 2021	419.2	241.9	176.8	0.6
December 31, 2022 [2]	**436.0**	**264.2**	**171.3**	**0.5**
Proved undeveloped reserves:				
December 31, 2019	352.7	226.7	126.0	–
December 31, 2020	304.1	98.2	205.9	–
December 31, 2021	297.7	101.6	196.0	0.1
December 31, 2022 [3]	**279.4**	**92.8**	**186.5**	**0.1**

[1] Includes proved reserves of 18.2 MMBOE, consisting of 16.5 MMBBL oil, 0.6 MMBBL NGLs and 5.6 BCF natural gas attributable to the noncontrolling interest in MP GOM.
[2] Includes proved developed reserves of 15.0 MMBOE, consisting of 13.7 MMBBL oil, 0.5 MMBBL NGLs and 4.2 BCF natural gas attributable to the noncontrolling interest in MP GOM.
[3] Includes proved undeveloped reserves of 3.2 MMBOE, consisting of 2.8 MMBBL oil, 0.1 MMBBL NGLs and 1.4 BCF 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 2019 – 2022 (Continued)

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 U.S. Gulf of Mexico.

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

Purchases and sales of properties - In 2022, the Company acquired incremental working interest in two producing fields in the U.S. Gulf of Mexico and divested working interest in one field in the U.S. Gulf of Mexico and a portion Eagle Ford Shale.

2021 Comments for Proved Equivalent Reserves Changes

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

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

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

2020 Comments for Proved Equivalent Reserves Changes

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

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

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

Schedule 2 – Summary of Proved Crude Oil Reserves Based on Average Prices for 2019 – 2022

(Millions of barrels)	Total	United States	Canada	Other
Proved developed and undeveloped crude oil reserves:				
December 31, 2019	423.9	377.8	45.3	0.8
Revisions of previous estimates	(137.4)	(116.8)	(19.8)	(0.8)
Extensions and discoveries	19.6	14.5	5.1	–
Sales of properties	(1.5)	(1.5)	–	–
Production	(38.1)	(33.4)	(4.7)	–
December 31, 2020	266.5	240.6	25.9	–
Revisions of previous estimates	39.3	31.1	7.5	0.7
Extensions and discoveries	14.1	13.5	0.6	–
Purchases of properties	6.4	1.3	5.2	–
Production	(34.9)	(31.5)	(3.3)	(0.1)
December 31, 2021	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**	**–**	**–**
Sales of properties	**(3.6)**	**(3.6)**	**–**	**–**
Production	**(35.5)**	**(32.7)**	**(2.5)**	**(0.3)**
December 31, 2022 [1]	**303.6**	**263.6**	**39.5**	**0.5**
Proved developed crude oil reserves:				
December 31, 2019	230.9	205.0	25.1	0.8
December 31, 2020	179.8	161.4	18.4	–
December 31, 2021	191.5	174.9	16.0	0.5
December 31, 2022 [2]	**209.0**	**194.4**	**14.2**	**0.4**
Proved undeveloped crude oil reserves:				
December 31, 2019	193.0	172.8	20.2	–
December 31, 2020	86.7	79.2	7.5	–
December 31, 2021	99.9	80.0	19.8	0.1
December 31, 2022 [3]	**94.6**	**69.2**	**25.3**	**0.1**

[1] Includes total proved reserves of 16.5 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.

[2] Includes proved developed reserves of 13.7 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.

[3] Includes proved undeveloped reserves of 2.8 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.

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

Schedule 2 – Summary of Proved Crude Oil Reserves Based on Average Prices for 2019 – 2022 (Continued)

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 U.S. Gulf of Mexico 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 U.S. in the Gulf of Mexico and the Eagle Ford Shale.

Purchases and sales of properties - In 2022, the Company acquired incremental working interest in two producing fields in the U.S. Gulf of Mexico and divested working interest in one field in the U.S. Gulf of Mexico and a portion of the Eagle Ford Shale.

2021 Comments for Proved Crude Oil Reserves Changes

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

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

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

2020 Comments for Proved Crude Oil Reserves Changes

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

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

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

Schedule 3 – Summary of Proved Natural Gas Liquids (NGL) Reserves Based on Average Prices for 2019 – 2022

(Millions of barrels)	Total	United States	Canada	Other
Proved developed and undeveloped NGL reserves:				
December 31, 2019	56.1	52.8	3.3	–
Revisions of previous estimates	(16.4)	(17.1)	0.7	–
Extensions and discoveries	2.8	2.7	0.1	–
Sales of properties	(0.1)	(0.1)	–	–
Production	(4.2)	(3.7)	(0.5)	–
December 31, 2020	38.2	34.6	3.6	–
Revisions of previous estimates	1.4	1.4	–	–
Extensions and discoveries	2.5	2.4	0.1	–
Purchases of properties	0.1	0.1	–	–
Production	(3.8)	(3.4)	(0.4)	–
December 31, 2021	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**	**–**
Purchases of properties	**0.3**	**0.3**	**–**	**–**
Sales of properties	**(0.2)**	**(0.2)**	**–**	**–**
Production	**(3.9)**	**(3.6)**	**(0.3)**	**–**
December 31, 2022 [1]	**41.7**	**37.6**	**4.1**	**–**
Proved developed NGL reserves:				
December 31, 2019	28.1	26.2	1.9	–
December 31, 2020	28.7	25.5	3.2	–
December 31, 2021	28.4	25.6	2.8	–
December 31, 2022 [2]	**29.7**	**27.4**	**2.3**	**–**
Proved undeveloped NGL reserves:				
December 31, 2019	28.0	26.6	1.4	–
December 31, 2020	9.5	9.1	0.4	–
December 31, 2021	10.0	9.5	0.5	–
December 31, 2022 [3]	**12.0**	**10.2**	**1.8**	**–**

[1] Includes total proved reserves of 0.6 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.

[2] Includes proved developed reserves of 0.5 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.

[3] Includes proved undeveloped reserves of 0.1 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.

Schedule 3 – Summary of Proved Natural Gas Liquids (NGL) Reserves Based on Average Prices for 2019 – 2022 (Continued)

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 U.S. Gulf of Mexico and the Eagle Ford Shale as well as in Canada at Kaybob Duvernay.

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

Purchases and sales of properties - In 2022, the Company acquired incremental working interest in two producing fields in the U.S. Gulf of Mexico and divested working interest in one field in the U.S. Gulf of Mexico and a portion of the Eagle Ford Shale.

2021 Comments for Proved Natural Gas Liquids Reserves Changes

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

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

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

2020 Comments for Proved Natural Gas Liquids Reserves Changes

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

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

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

Schedule 4 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2019 – 2022

(Billions of cubic feet)	Total	United States	Canada	Other
Proved developed and undeveloped natural gas reserves:				
December 31, 2019	2,069.7	416.8	1,652.9	–
Revisions of previous estimates	(245.4)	(76.2)	(169.2)	–
Extensions and discoveries	767.2	14.0	753.2	–
Sales of properties	(0.7)	(0.7)	–	–
Production	(129.8)	(34.4)	(95.4)	–
December 31, 2020	2,461.0	319.5	2,141.5	–
Revisions of previous estimates	(562.2)	18.7	(581.0)	0.2
Extensions and discoveries	556.7	13.5	543.2	–
Purchases of properties	5.4	1.5	3.9	–
Sale of properties	(4.4)	–	(4.4)	–
Production	(134.2)	(32.8)	(101.4)	–
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**	**–**	**–**
Sales of properties	**(3.6)**	**(3.6)**	**–**	**–**
Production	**(146.9)**	**(33.7)**	**(113.2)**	**–**
December 31, 2022 [1,4]	**2,219.9**	**334.9**	**1,884.8**	**0.2**
Proved developed natural gas reserves:				
December 31, 2019	1,279.8	253.1	1,026.7	–
December 31, 2020	1,213.8	260.2	953.6	–
December 31, 2021	1,196.0	248.1	947.7	0.2
December 31, 2022 [2,4]	**1,183.1**	**254.1**	**928.8**	**0.2**
Proved undeveloped natural gas reserves:				
December 31, 2019	789.9	163.7	626.2	–
December 31, 2020	1,247.2	59.3	1,187.9	–
December 31, 2021	1,126.4	72.2	1,054.1	–
December 31, 2022 [3]	**1,036.8**	**80.8**	**956.0**	**–**

[1] Includes total proved reserves of 5.6 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.

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

[3] Includes proved undeveloped reserves of 1.4 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.

[4] Includes proved natural gas reserves to be consumed in operations as fuel of 74.9 BCF and 43.5 BCF for the U.S. and Canada, respectively, with 0.8 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 2019 – 2022 (Continued)

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 Canada at Tupper Montney.

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

Purchases and sales of properties - In 2022, the Company acquired incremental working interest in two producing fields in the U.S. Gulf of Mexico and divested working interest in one field in the U.S. Gulf of Mexico and a portion of the Eagle Ford Shale.

2021 Comments for Proved Natural Gas Reserves Changes

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

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

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

2020 Comments for Proved Natural Gas Reserves Changes

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

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

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

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

(Millions of dollars)	United States	Canada [1]	Other	Total
Year ended December 31, 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**	**$ (5.7)**	**$ 1,041.4**
Year ended December 31, 2021				
Property acquisition costs				
Unproved	$ 8.8	$ –	$ –	$ 8.8
Proved	19.9	(20.4)	–	(0.5)
Total acquisition costs	28.7	(20.4)	–	8.3
Exploration costs	31.7	0.4	30.1	62.2
Development costs	513.2	102.4	3.7	619.3
Total costs incurred	573.6	82.4	33.8	689.8
Charged to expense				
Dry hole expense	17.3	–	–	17.3
Geophysical and other costs	13.1	0.4	19.3	32.8
Total charged to expense	30.4	0.4	19.3	50.1
Property additions	$ 543.2	$ 82.0	$ 14.5	$ 639.7
Year ended December 31, 2020				
Property acquisition costs				
Unproved	$ 6.5	$ 0.5	$ 7.3	$ 14.3
Proved	0.2	–	–	0.2
Total acquisition costs	6.7	0.5	7.3	14.5
Exploration costs	34.3	(0.4)	24.7	58.6
Development costs	609.2	120.8	6.8	736.8
Total costs incurred	650.2	120.9	38.8	809.9
Charged to expense				
Geophysical and other costs	14.3	0.7	23.6	38.6
Total charged to expense	14.3	0.7	23.6	38.6
Property additions	$ 635.9	$ 120.2	$ 15.2	$ 771.3

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

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

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

(*Millions of dollars*)	United States	Canada	Other	Total
Year ended December 31, 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 (benefits)	**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**
Year ended December 31, 2021				
Revenues				
Crude oil and natural gas liquids sales	$ 2,199.7	$ 228.9	$ 4.9	$ 2,433.5
Natural gas sales	121.8	245.9	–	367.7
Total oil and natural gas revenues	2,321.5	474.8	4.9	2,801.2
Other operating revenues	16.0	1.5	–	17.5
Total revenues	2,337.5	476.3	4.9	2,818.7
Costs and expenses				
Lease operating expenses	406.4	136.3	(3.2)	539.5
Severance and ad valorem taxes	39.6	1.6	–	41.2
Transportation, gathering and processing	126.5	60.5	–	187.0
Exploration costs charged to expense	30.4	0.4	19.3	50.1
Undeveloped lease amortization	11.1	0.2	7.6	18.9
Depreciation, depletion and amortization	616.5	163.8	1.8	782.1
Accretion of asset retirement obligations	36.9	9.7	–	46.6
Impairment of assets	–	171.3	18.0	189.3
Selling and general expenses	20.5	16.5	6.6	43.6
Other expenses	99.4	(66.2)	(2.2)	31.0
Total costs and expenses	1,387.3	494.1	47.9	1,929.3
Results of operations before taxes	950.2	(17.8)	(43.0)	889.4
Income tax expense (benefit)	183.9	(1.7)	(9.5)	172.7
Results of operations	$ 766.3	$ (16.1)	$ (33.5)	$ 716.7

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

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

(*Millions of dollars*)	United States	Canada	Other	Total
Year ended December 31, 2020				
Revenues				
Crude oil and natural gas liquids sales	$ 1,335.8	$ 174.0	$ 1.8	$ 1,511.6
Natural gas sales	69.4	170.6	–	240.1
Total oil and natural gas revenues	1,405.3	344.6	1.8	1,751.7
Other operating revenues	6.5	1.2	–	7.7
Total revenues	1,411.8	345.8	1.8	1,759.4
Costs and expenses				
Lease operating expenses	476.9	121.6	1.6	600.1
Severance and ad valorem taxes	27.2	1.3	–	28.5
Transportation, gathering and processing	127.7	44.7	–	172.4
Restructuring expenses	1.2	–	–	1.2
Exploration costs charged to expense	35.5	0.6	23.6	59.7
Undeveloped lease amortization	17.2	0.4	9.2	26.8
Depreciation, depletion and amortization	749.4	213.2	2.3	964.9
Accretion of asset retirement obligations	36.6	5.6	–	42.2
Impairment of assets	1,152.5	–	39.7	1,192.2
Selling and general expenses	24.6	17.1	7.1	48.8
Other expenses	21.5	(2.3)	1.8	21.0
Total costs and expenses	2,670.3	402.2	85.3	3,157.8
Results of operations before taxes	(1,258.5)	(56.4)	(83.5)	(1,398.4)
Income tax expense (benefit)	(244.2)	(21.4)	2.1	(263.5)
Results of operations	$ (1,014.3)	$ (35.0)	$ (85.6)	$ (1,134.9)

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

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

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

1 Includes noncontrolling interest in MP GOM.
2 Totals within the table may not add as a result of rounding.

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

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

(Millions of dollars)	**2022**	2021	2020
Net changes in prices and production costs[2]	**$ 4,812.2**	$ 5,962.1	$ (5,942.1)
Net changes in development costs	**(531.1)**	(503.6)	2,215.1
Sales and transfers of oil and natural gas produced, net of production costs	**(2,917.4)**	(2,220.5)	(1,123.1)
Net change due to extensions and discoveries	**1,223.5**	908.5	568.5
Net change due to purchases and sales of proved reserves	**102.1**	63.1	(14.6)
Development costs incurred	**769.3**	619.3	736.8
Accretion of discount	**802.6**	267.2	699.3
Revisions of previous quantity estimates	**1,652.9**	277.1	(1,461.3)
Net change in income taxes	**(1,399.9)**	(692.8)	1,112.4
Net increase (decrease)	**4,514.2**	4,680.4	(3,209.0)
Standardized measure at January 1	**7,299.0**	2,618.6	5,827.6
Standardized measure at December 31	**$ 11,813.2**	$ 7,299.0	$ 2,618.6

1 Includes noncontrolling interest in MP GOM.
2 The average prices used for 2022 were $93.67 per barrel for NYMEX crude oil (WTI) and $6.36 per MCF for natural gas (Henry Hub). The average prices used for 2021 were $66.56 per barrel for NYMEX crude oil (WTI) and $3.60 per MCF for natural gas (Henry Hub). The average prices used for 2020 were $39.57 per barrel for NYMEX crude oil (WTI) and $1.98 per MCF for natural gas (Henry Hub).

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

(*Millions of dollars*)	United States	Canada	Other	Total
December 31, 2022				
Unproved oil and natural gas properties	**$ 494.6**	**$ 19.2**	**$ 135.1**	**$ 648.9**
Proved oil and natural gas properties	**15,051.9**	**4,684.8**	**55.9**	**19,792.6**
Gross capitalized costs	**15,546.5**	**4,704.0**	**191.0**	**20,441.5**
Accumulated depreciation, depletion and amortization				
Unproved oil and natural gas properties	**(117.8)**	**–**	**(14.7)**	**(132.5)**
Proved oil and natural gas properties	**(8,873.6)**	**(3,208.0)**	**(41.3)**	**(12,122.9)**
Net capitalized costs	**$ 6,555.1**	**$ 1,496.0**	**$ 135.0**	**$ 8,186.1**
December 31, 2021				
Unproved oil and natural gas properties	$ 602.8	$ 17.7	$ 141.7	$ 762.2
Proved oil and natural gas properties	14,690.7	4,865.1	100.0	19,655.8
Gross capitalized costs	15,293.5	4,882.8	241.7	20,418.0
Accumulated depreciation, depletion and amortization				
Unproved oil and natural gas properties	(109.1)	–	(22.0)	(131.1)
Proved oil and natural gas properties	(8,821.5)	(3,320.5)	(69.0)	(12,211.0)
Net capitalized costs	$ 6,362.9	$ 1,562.3	$ 150.7	$ 8,075.9

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

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

(Millions of dollars except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year [1]
Year ended December 31, 2022					
Revenue from contracts with customers	**$ 871.4**	**$ 1,196.2**	**$ 1,166.4**	**$ 986.1**	**$ 4,220.1**
Income (loss) from continuing operations before income taxes	**(81.9)**	**515.5**	**734.0**	**282.7**	**1,450.3**
Income (loss) from continuing operations	**(64.9)**	**410.4**	**574.5**	**220.8**	**1,140.8**
Net income (loss) including noncontrolling interest	**(65.5)**	**409.5**	**574.1**	**220.6**	**1,138.7**
Net income (loss) attributable to Murphy	**(113.3)**	**350.6**	**528.3**	**199.4**	**965.0**
Income (loss) from continuing operations per Common share [2]					
Basic	**(0.73)**	**2.27**	**3.40**	**1.28**	**6.23**
Diluted	**(0.73)**	**2.24**	**3.36**	**1.26**	**6.14**
Net income (loss) per Common share [2]					
Basic	**(0.73)**	**2.26**	**3.40**	**1.28**	**6.22**
Diluted	**(0.73)**	**2.23**	**3.36**	**1.26**	**6.13**
Cash dividend per Common share	**0.150**	**0.175**	**0.250**	**0.250**	**0.825**
Year ended December 31, 2021					
Revenue from contracts with customers	$ 592.5	$ 758.8	$ 687.6	$ 762.3	$ 2,801.2
Income (loss) from continuing operations before income taxes	(355.2)	(38.1)	174.9	261.3	42.9
Income (loss) from continuing operations	(267.0)	(26.9)	138.0	204.7	48.8
Net income (loss) including noncontrolling interest	(266.8)	(27.0)	137.3	204.0	47.5
Net income (loss) attributable to Murphy	(287.4)	(63.1)	108.4	168.4	(73.7)
Income (loss) from continuing operations per Common share [2]					
Basic	(1.87)	(0.41)	0.70	1.09	(0.47)
Diluted	(1.87)	(0.41)	0.70	1.08	(0.47)
Net income (loss) per Common share [2]					
Basic	(1.87)	(0.41)	0.70	1.09	(0.48)
Diluted	(1.87)	(0.41)	0.70	1.09	(0.48)
Cash dividend per Common share	0.125	0.125	0.125	0.125	0.500

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

[2] 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
2022					
Deducted from asset accounts:					
Allowance for doubtful accounts	**$ 1.6**	**$ –**	**$ –**	**$ –**	**$ 1.6**
Deferred tax asset valuation allowance	**111.2**	**24.8**	**–**	**–**	**136.0**
2021					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 1.6	$ –	$ –	$ –	$ 1.6
Deferred tax asset valuation allowance	106.4	4.8	–	–	111.2
2020					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 1.6	$ –	$ –	$ –	$ 1.6
Deferred tax asset valuation allowance	103.1	3.3	–	–	106.4

GLOSSARY

2D seismic

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

3D seismic

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

deepwater

offshore location in greater than 1,000 feet of water

downstream

refining and marketing operations

dry hole

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

exploratory

wildcat and delineation, e.g., exploratory wells

hydrocarbons

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

operator

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

production sharing contract

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

unitization

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

upstream

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

working interest

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

ABBREVIATIONS

ARO - Asset Retirement Obligation

ASU - Accounting Standards Update

BCF - Billion cubic feet

BOEPD - Barrel of oil equivalent per day

DE&I - Diversity, Equity and Inclusion

ESG - Environmental, Social and Governance

FASB - Financial Accounting Standards Board

GAAP - U.S. Generally Accepted Accounting Principles

GHG - Greenhouse gas

GK - Gumusut/Kakap

LOE - Lease operating expense

MCF - Thousand cubic feet

MMBBL - Million barrels of oil

MMBOE - Million barrels of oil equivalent

MMCF - Million cubic feet

MMCFD – Million cubic feet per day

MOCL - Murphy Oil Company Ltd.

NCI - Noncontrolling interest

NGL - Natural gas liquids

NYMEX - New York Mercantile Exchange

OSHA - Occupational Safety and Health Act

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

QRE - Qualified Reserve Estimators

RCF - Revolving Credit Facility

SEC - U.S. Securities and Exchange Commission

SOFR - Secured Overnight Financing Rate

TGP - Transmission, gathering and processing

WTI - West Texas Intermediate

Corporate Information

BOARD OF DIRECTORS

Claiborne P. Deming
Chairman of the Board
Retired President and Chief Executive Officer,
Murphy Oil Corporation

Roger W. Jenkins
President and Chief Executive Officer,
Murphy Oil Corporation

T. Jay Collins ● ● ●
Retired President and Chief Executive Officer,
Oceaneering International, Inc.

Steven A. Cossé ● ●
Retired President and Chief Executive Officer,
Murphy Oil Corporation

Lawrence R. Dickerson ● ●
Retired President and Chief Executive Officer,
Diamond Offshore Drilling, Inc.

Michelle A. Earley ● ●
Partner, O'Melveny & Meyers LLP

Elisabeth W. Keller ● ● ●
Retired President, Inglewood Plantation, LLC

James V. Kelley ● ●
Retired President and Chief Operating Officer,
BancorpSouth, Inc.

R. Madison Murphy ●
Chairman of the Board, Murphy USA

Jeffrey W. Nolan ● ●
Retired President and Chief Executive Officer,
Loutre Land and Timber Company

Robert N. Ryan, Jr. ● ● ●
Retired Vice President, Chevron Corporation

Neal E. Schmale ● ●
Retired President and Chief Operating Officer,
Sempra Energy

Laura A. Sugg ● ●
Retired Senior Executive, ConocoPhillips

Committee Members Legend
- ● Member of Audit Committee
- ● Member of Compensation Committee
- ● Member of Finance Committee
- ● Member of Health, Safety, Environment and Corporate Responsibility Committee
- ● Member of Nominating and Governance Committee

CORPORATE OFFICERS

Roger W. Jenkins
President and Chief Executive Officer

Thomas J. Mireles
Executive Vice President and Chief Financial Officer

Eric M. Hambly
Executive Vice President, Operations

E. Ted Botner
Senior Vice President, General Counsel and Corporate Secretary

Daniel R. Hanchera
Senior Vice President, Business Development

John B. Gardner
Vice President, Marketing and Supply Chain

Leyster L. Jumawan
Vice President, Corporate Planning and Treasurer

Maria A. Martinez
Vice President, Human Resources and Administration

Meenambigai Palanivelu
Vice President, Sustainability

Louis W. Utsch
Vice President, Tax

Paul D. Vaughan
Vice President, Controller

Kelly L. Whitley
Vice President, Investor Relations and Communication

STOCKHOLDER INFORMATION

Annual Meeting
The 2023 Annual Meeting of Stockholders will be held on Wednesday, May 10, 2023, at 10:00 a.m. CDT, in a virtual-only format via live audio webcast at www.virtualshareholdermeeting.com/MUR2023.

Common Stock
Listed New York Stock Exchange
Ticker Symbol: MUR

Transfer Agent and Registrar
Computershare
P.O. Box 43078
Providence, RI 02940-3078
Toll-free: 888.239.5303
Outside the US: 732.645.4155

For overnight deliveries:
Computershare
150 Royall Street, Suite 101
Canton, MA 02021

Stockholder website:
www.computershare.com/investor

Stockholder online inquiries:
www-us.computershare.com/Investor/Contact

Documents Available
Copies of the Corporation's 2022 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Annual Proxy Statement filed with the Securities and Exchange Commission, as well as the Corporation's Code of Business Conduct and Ethics, Corporate Governance Guidelines, and charters of the Audit Committee, Compensation Committee, Finance Committee, Health, Safety, Environment and Corporate Responsibility Committee, and Nominating and Governance Committee of the Board of Directors are available, without charge, on our website below or upon written request to:

E. Ted Botner
Senior Vice President, General Counsel and Corporate Secretary
Ted_Botner@murphyoilcorp.com

Members of the financial community:
Kelly L. Whitley
Vice President, Investor Relations and Communications
Kelly_Whitley@murphyoilcorp.com

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Houston, Texas 77024
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Forward-Looking Statements
See information regarding forward-looking statements on page 54 of the Form 10-K.

MURPHY OIL CORPORATION

OUR PURPOSE

We believe in providing energy that empowers people.

OUR MISSION

We challenge the norm, tap into our strong legacy and use our foresight and financial discipline to deliver inspired energy solutions.

OUR VISION

We see a future where we are an industry leader who is positively impacting lives for the next 100 years and beyond.

OUR BEHAVIORS

Do Right Always

- Respect people, safety, environment and the law
- Follow through on commitments
- Share openly and accurately
- Make it better

Stay With It

- Show resilience
- Lean into challenges
- Support each other
- Consider the implications

Think Beyond Possible

- Offer solutions
- Step up and lead
- Don't settle for "good enough"
- Embrace new opportunities

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MUR
LISTED
NYSE