Marathon Oil

Dear Shareholders,

2021 was a year of comprehensive delivery against our framework for success, as evidenced by bottom line financial results and environmental, social and governance (ESG) excellence that compete not only with the best companies in energy, but with the best in the S&P 500.

We stayed disciplined and did not waver from our reinvestment rate driven capital allocation priorities, generating over $2.2 billion of free cash flow, including about $900 million during fourth quarter alone. We dramatically enhanced our balance sheet quality by accelerating $1.4 billion of gross debt reduction.

We then successfully transitioned to market leading return of capital to our equity investors, prioritizing our shareholders as the first call on cash flow generation via our differentiated percentage of cash flow framework. During fourth quarter, we returned more than 70% of our cash flow from operations to equity investors through the powerful combination of a sustainable and competitive base dividend and consistent share repurchases, significantly exceeding our minimum 40% commitment.

While others in our space may once again be focused on growing their production, we are focused on growing the per share financial metrics that matter most to our equity valuation – our cash flow per share and our free cash flow per share. Since October 2021, we have executed over $1 billion of share repurchases – achieving an 8% reduction to our outstanding share count in just 4½ months. Beyond driving significant underlying per share growth, share repurchases are highly synergistic with base dividend growth over time and we recently raised our quarterly base dividend for the fourth consecutive quarter.

In 2021, we also achieved significant progress against core safety and environmental objectives including the second best annual Total Recordable Incident Rate[1] (TRIR) since becoming an independent E&P. We also achieved our target to reduce greenhouse gas (GHG) intensity by at least 30% relative to 2019 baseline and improved total company gas capture[2] to 98.8%.

Early in 2022, we announced new quantitative environmental objectives that highlight our commitment to meeting global energy demand with leading environmental performance. This includes near, medium and long-term goals focused on GHG intensity, methane intensity and gas capture, and a commitment to the 2030 World Bank Zero Routine Flaring initiative.

As we look ahead to 2022 and beyond, you can expect more of the same from our company: peer leading capital efficiency and operational execution, significant free cash flow generation and market leading return of capital to shareholders, all underpinned by our commitment to continue to drive ESG excellence.

Finally, we would like to thank all of our dedicated employees and contractors who made 2021 another exceptional year for our company.

Lee M. Tillman

Lee M. Tillman
Chairman, President and Chief Executive Officer

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[1] *Total Recordable Incident Rate measures combined employee and contractor workforce incidents per 200,000 work hours.*

[2] *Gas capture percentage is the percentage of volume of wellhead natural gas captured upstream of low pressure separation and/or storage equipment such as vapor recovery towers and tanks.*

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

# FORM 10-K

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

**For the Fiscal Year Ended December 31, 2021**

☐ **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 1-1513**

# Marathon Oil Corporation

(Exact name of registrant as specified in its charter)

| **Delaware** | **25-0996816** |
|---|---|
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

**990 Town and Country Boulevard, Houston, Texas 77024-2217**
(Address of principal executive offices)
**(713) 629-6600**
(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, par value $1.00 | MRO | 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 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, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer", "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

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

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

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

The aggregate market value of Common Stock held by non-affiliates as of June 30, 2021: $10,705 million. This amount is based on the closing price of the registrant's Common Stock on the New York Stock Exchange on that date. Shares of Common Stock held by executive officers and directors of the registrant are not included in the computation. The registrant, solely for the purpose of this required presentation, has deemed its directors and executive officers to be affiliates.

There were 730,765,163 shares of Marathon Oil Corporation Common Stock outstanding as of February 11, 2022.

Documents Incorporated By Reference:
Portions of the registrant's proxy statement relating to its 2022 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this report.

*MARATHON OIL CORPORATION*

Unless the context otherwise indicates, references to “Marathon Oil,” “we,” “our” or “us” in this Annual Report on Form 10-K are references to Marathon Oil Corporation, including its wholly owned and majority-owned subsidiaries, and its ownership interests in equity method investees (corporate entities, partnerships, limited liability companies and other ventures over which Marathon Oil exerts significant influence by virtue of its ownership interest).

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## Definitions

Throughout this report, the following company or industry specific terms and abbreviations are used.

*AMPCO* – Atlantic Methanol Production Company LLC, a company located in Equatorial Guinea in which we own a 45% equity interest.

*AMT* – Alternative minimum tax.

*bbl* – One stock tank barrel, which is 42 United States gallons liquid volume.

*boe* – Barrels of oil equivalent.

*btu* – British thermal unit, an energy equivalence measure.

*BLM* – Bureau of Land Management.

*Capital budget* – Includes capital expenditures, cash investments in equity method investees and other investments, exploration costs that are expensed as incurred rather than capitalized, such as geological and geophysical costs and certain staff costs, and other miscellaneous investment expenditures.

*CWA* – Clean Water Act.

*DD&A* – Depreciation, depletion and amortization.

*Development well* – A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

*Dry well* – A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or gas well.

*E.G.* – Equatorial Guinea.

*EGHoldings or EG LNG* – Equatorial Guinea LNG Holdings Limited and its wholly owned subsidiaries, a liquefied natural gas production company located in E.G. in which we own a 56% equity interest.

*ESG* – Environmental, safety and governance.

*EPA* – United States Environmental Protection Agency.

*Exploratory well* – A well drilled to find oil or natural gas in an unproved area or find a new reservoir in a field previously found to be productive in another reservoir.

*FASB* – Financial Accounting Standards Board.

*GHG* – Greenhouse gas.

*Henry Hub* – a natural gas benchmark price quoted at settlement date average.

*IRS* – United States Internal Revenue Service.

*Kurdistan* – Kurdistan Region of Iraq.

*LIBOR* – London Interbank Offered Rate.

*LNG* – Liquefied natural gas.

*LPG* – Liquefied petroleum gas.

*Liquid hydrocarbons or liquids* – Collectively, crude oil, condensate and natural gas liquids.

*Marathon Oil* – Marathon Oil Corporation, including wholly owned and majority-owned subsidiaries, and ownership interests in equity method investees (corporate entities, partnerships, limited liability companies and other ventures over which Marathon Oil exerts significant influence by virtue of its ownership interest). The company as it exists following the June 30, 2011 spin-off of the refining, marketing and transportation operations.

*mbbld* – Thousand barrels per day.

*mboed* – Thousand barrels of oil equivalent per day.

*mcf* – Thousand cubic feet.

*mmbbl* – Million barrels.

*mmboe* – Million barrels of oil equivalent. Natural gas is converted on the basis of six mcf of gas per one barrel of crude oil equivalent.

*mmbtu* – Million British thermal units.

*mmcfd* – Million stabilized cubic feet per day.

*mmta* – Million metric tonnes per annum.

*mt* – Metric tonnes.

*mtd* – Metric tonnes per day.

*NAAQS* – National Ambient Air Quality Standard.

*MEH* – Magellan East Houston, an oil index benchmark price of WTI at Magellan East Houston.

*Net acres or Net wells* – The sum of the fractional working interests owned by us in gross acres or gross wells.

*NGL or NGLs* – Natural gas liquid or natural gas liquids, which are naturally occurring substances found in natural gas, including ethane, butane, isobutane, propane and natural gasoline, which can be collectively removed from produced natural gas, separated into these substances and sold.

*NYMEX* – New York Mercantile Exchange.

*OPEC* – Organization of Petroleum Exporting Countries.

*Operational availability* – A term used to measure the ability of an asset to produce to its maximum capacity over a specified period of time, after consideration of planned maintenance.

*Productive well* – A well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.

*Proved developed reserves* – Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or for which the cost of the required equipment is relatively minor compared to the cost of a new well.

*Proved reserves* – Proved crude oil and condensate, NGLs and natural gas reserves are those quantities of crude oil and condensate, NGLs 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-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

*Proved undeveloped reserves* – Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undrilled locations can be classified as having proved undeveloped reserves if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic viability at greater distances.

*REx* – Resource play exploration.

*Royalty interest* – An interest in an oil or natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

*SAR or SARs* – Stock appreciation right or stock appreciation rights.

*SCOOP* – South Central Oklahoma Oil Province.

*SEC* – United States Securities and Exchange Commission.

*Seismic* – An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formation (3-D seismic provides three-dimensional pictures and 4-D factors in changes that occurred over time).

*STACK* – Sooner Trend (oil field), Anadarko (basin), Canadian (and) Kingfisher (counties) in Oklahoma.

*Total proved reserves* – The summation of proved developed reserves and proved undeveloped reserves.

*Turnaround* – A planned major maintenance program the costs for which are expensed in the period incurred and can include the costs of contractor repair services, materials and supplies, equipment rentals and our labor costs.

*U.K.* – United Kingdom.

*U.S.* – United States of America.

*U.S. resource plays* – Consists of our unconventional properties in the Eagle Ford in Texas, the Bakken in North Dakota, STACK and SCOOP in Oklahoma and Northern Delaware in New Mexico.

*U.S. GAAP* – U.S. Generally Accepted Accounting Principles.

*Working interest* – The interest in a mineral property, which gives the owner that share of production from the property. A working interest owner bears that share of the costs of exploration, development and production in return for a share of production. Working interests are sometimes burdened by overriding royalty interests or other interests.

*WOTUS* – Waters of the United States.

*WTI* – West Texas Intermediate crude oil, an oil index benchmark price as quoted by NYMEX.

## Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These are statements, other than statements of historical fact, that give current expectations or forecasts of future events, including without limitation: our operational, financial and growth strategies, including drilling plans and projects, planned wells, rig count, inventory, seismic, exploration plans, maintenance activities, drilling and completion improvements, cost reductions, and financial flexibility; our ability to successfully effect those strategies and the expected timing and results thereof; our 2022 capital budget and the planned allocation thereof; planned capital expenditures and the impact thereof; expectations regarding future economic and market conditions and their effects on us; our financial and operational outlook, and ability to fulfill that outlook; our financial position, balance sheet, liquidity and capital resources, and the benefits thereof; resource and asset potential; reserve estimates; growth expectations; and future production and sales expectations, and the drivers thereof. In addition, many forward-looking statements may be identified by the use of forward-looking terminology such as "anticipates," "believes," "could," "estimates," "expects," "may," "plans," "projects," "should," "targets," "would" or similar words indicating that future outcomes are uncertain. While we believe that our assumptions concerning future events are reasonable, these expectations may not prove to be correct. A number of factors could cause results to differ materially from those indicated by such forward-looking statements including, but not limited to:

- conditions in the oil and gas industry, including supply and demand levels for crude oil and condensate, NGLs and natural gas and the resulting impact on price;
- changes in expected reserve or production levels;
- changes in political or economic conditions in the U.S. and E.G., including changes in foreign currency exchange rates, interest rates, inflation rates, and global and domestic market conditions;
- actions taken by the members of OPEC and Russia affecting the production and pricing of crude oil and other global and domestic political, economic or diplomatic developments;
- capital available for exploration and development;
- risks related to our hedging activities;
- voluntary or involuntary curtailments, delays or cancellations of certain drilling activities;
- well production timing;
- liabilities or corrective actions resulting from litigation, other proceedings and investigations or alleged violations of law or permits;
- drilling and operating risks;
- lack of, or disruption in, access to storage capacity, pipelines or other transportation methods;
- availability of drilling rigs, materials and labor, including the costs associated therewith;
- difficulty in obtaining necessary approvals and permits;
- the availability, cost, terms and timing of issuance or execution of, competition for, and challenges to, mineral licenses and leases and governmental and other permits and rights-of-way, and our ability to retain mineral licenses and leases;
- non-performance by third parties of their contractual obligations, including due to bankruptcy;
- unexpected events that may impact distributions from our equity method investees;
- unforeseen hazards such as weather conditions, a health pandemic (including COVID-19), acts of war or terrorist acts and the governmental or military response thereto;
- security threats, including cybersecurity threats and disruptions to our business and operations from breaches of our information technology systems, or breaches of the information technology systems, facilities and infrastructure of third parties with which we transact business;
- changes in safety, health, environmental, tax, currency and other regulations, or requirements or initiatives including those addressing the impact of global climate change, air emissions or water management;
- other geological, operating and economic considerations; and
- other factors discussed in Item 1. Business, Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and elsewhere in this report.

All forward-looking statements included in this report are based on information available to us on the date of this report. Except as required by law, we undertake no obligation to revise or update any forward-looking statements as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

## PART I

## Items 1. and 2. Business and Properties

### General and Business Strategy

#### General

Marathon Oil Corporation (NYSE: MRO) is an independent exploration and production company incorporated in 2001, focused on U.S. resource plays: Eagle Ford in Texas, Bakken in North Dakota, STACK and SCOOP in Oklahoma and Northern Delaware in New Mexico. Our U.S. assets are complemented by our international operations in E.G. Our corporate headquarters is located at 990 Town and Country Boulevard, Houston, Texas 77024-2217 and our telephone number is (713) 629-6600. Each of our two reportable operating segments are organized by geographic location and managed according to the nature of the products and services offered. The two segments are:

- United States – explores for, produces and markets crude oil and condensate, NGLs and natural gas in the United States;
- International – produces and markets crude oil and condensate, NGLs and natural gas outside of the United States as well as produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.

#### Business Strategy

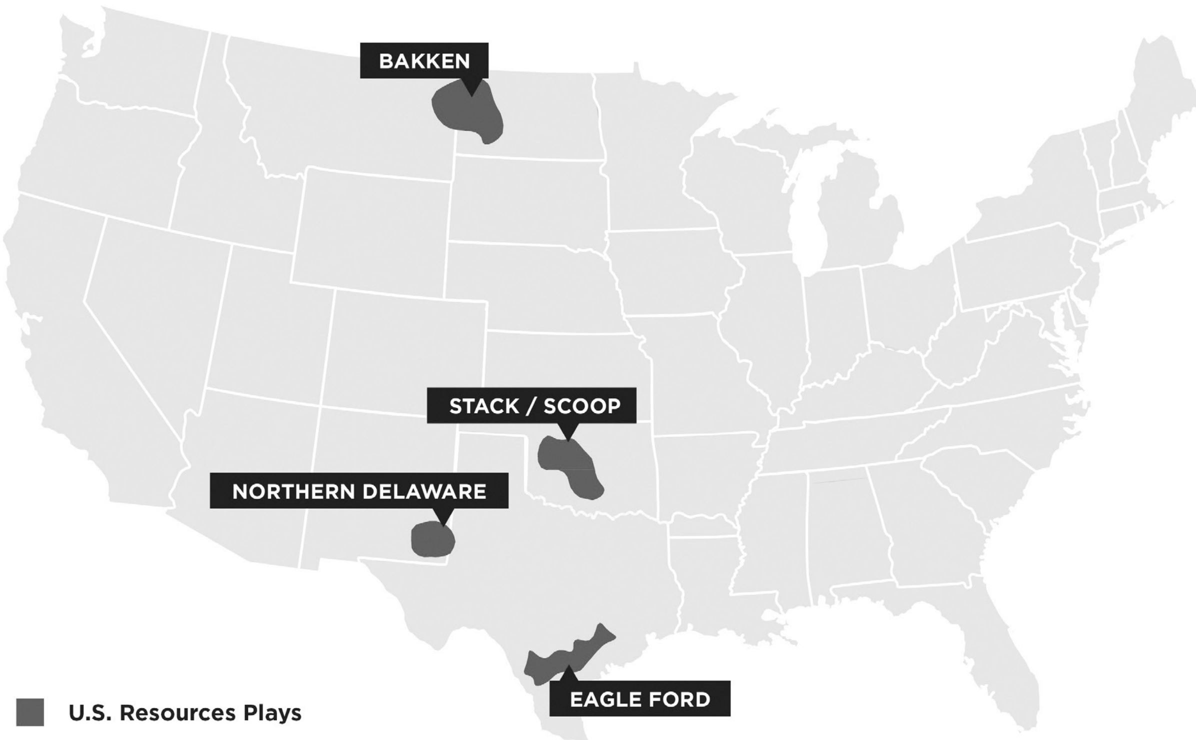
Our overall business strategy is to responsibly deliver competitive corporate level returns, free cash flow and cash returns to shareholders, all of which are sustainable and resilient through long-term commodity price cycles. We expect to achieve our business strategy by adherence to a disciplined reinvestment rate capital allocation framework that limits our capital expenditures relative to our expected cash flow from operations. Keeping our workforce safe, maintaining a strong balance sheet, responsibly meeting global energy demand with a focus on continuously improving environmental performance, serving as a trusted partner to our local communities and maintaining best in-class corporate governance standards are foundational to the execution of our strategy.


In February 2022, we announced a 2022 capital budget of $1.2 billion that prioritizes free cash flow generation over production growth, consistent with our disciplined capital allocation framework. We expect this maintenance-level capital budget will allow us to keep total company oil production in 2022 consistent with the oil production average from 2021.

The risks associated with COVID-19 impacted our workforce and the way we meet our business objectives. Throughout the COVID-19 pandemic, we continue to leverage our emergency response protocols and business continuity plans to help manage our operations and workforce. Our corporate workforce worked remotely for a significant period of time when the pandemic began. In late 2020, we implemented a process for a phased return of employees to the office, and during April 2021, the majority of our corporate workforce returned to the office. Working remotely did not significantly impact our ability to maintain operations, allowed our field offices to operate without any disruption and did not cause us to incur significant additional expenses.

We have taken action in response to the macro challenges associated with the COVID-19 pandemic. Our response has included reducing our 2020 and 2021 capital expenditure programs, lowering our cost structure and improving our balance sheet through gross debt reduction. We believe our financial strength, quality portfolio, ongoing focus on maintaining a competitive cost structure and disciplined capital allocation framework better position us to navigate a variety of commodity price environments. See **Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations**, for a more detailed discussion of our operating results, cash flows and liquidity.

Our portfolio is concentrated in our core operations in the U.S. resource plays and E.G. The map below shows the locations of our U.S. resource plays:



## Segment Information

In the following discussion regarding our United States and International segments, references to net wells, acres, sales or investment indicate our ownership interest or share, as the context requires.

### United States Segment

We are engaged in oil and gas exploration, development and production activities in the U.S. Our primary focus in the United States segment is concentrated within our four high-quality resource plays. See **Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations** for further detail on current year results.

***United States – U.S. Resource Plays***

*Eagle Ford* – We have been operating in the South Texas Eagle Ford play since 2011, where our acreage is located in Karnes, Atascosa, Gonzales and Lavaca Counties. We operate 32 central gathering and treating facilities across the play that support more than 1,600 producing wells. We also own and operate the Sugarloaf gathering system, a 42-mile natural gas pipeline through the heart of our acreage in Karnes and Atascosa Counties.

*Bakken* – We have been operating in the Williston Basin since 2006. The majority of our core acreage is within McKenzie, Mountrail and Dunn Counties in North Dakota targeting the Middle Bakken and Three Forks reservoirs.

*Oklahoma* – With a history in Oklahoma that dates back more than 100 years, our primary focus has been development in the STACK Meramec and SCOOP Woodford, while progressing delineation of other plays across our acreage. We primarily hold net acreage with rights to the Woodford, Springer, Meramec, Osage and other prospect intervals, with a majority of this in the SCOOP and STACK.

*Northern Delaware* – We have been operating in the Northern Delaware basin, which is located within the greater Permian area, since closing on two major acquisitions in 2017. Our focus has been to advance our position through execution of strategic acreage trades, progress early delineation and development of our acreage, improve our cost structure and secure midstream solutions. We have the majority of our acreage in Eddy and Lea counties primarily in the Wolfcamp and Bone Spring New Mexico plays.

***United States – Resource Exploration***

Our 2021 Resource Play Exploration drilling and completion program was focused on the continued delineation of our contiguous 50,000 net acreage position in the Texas Delaware Oil Play. During the second half of 2021, we brought online our first multi-well pad in the play. We have now brought online a total of 9 successful wells in this new play, including 6 Woodford wells and 3 Meramec wells. These wells have advanced our geologic understanding of the play and have demonstrated strong productivity, low decline and low water/oil ratios.

### International Segment

We are engaged in oil and gas development and production activities in E.G. We include the results of our investments in the LPG processing plant, LNG and methanol production operations in E.G. in our International segment.

***International***

*Equatorial Guinea* – We own a 63% and an 80% operated working interest in two separate production sharing contracts (Alba PSC and Block D PSC, respectively), which we produce from the Alba field, located offshore E.G. These production sharing contracts were unitized in 2017 resulting in the Alba Unit in which we own a 64% operated working interest.

*Equatorial Guinea – Gas Processing* – The following facilities located on Bioko Island, all accounted for as equity method investments, allow us to further monetize natural gas production from the Alba field.

We own a 52% interest in Alba Plant LLC, which operates an onshore LPG processing plant. Alba field natural gas is processed by the LPG plant under a fixed-price long-term contract. The LPG plant extracts secondary condensate and LPG from the natural gas stream and uses some of the remaining dry natural gas in its operations.

We also own 56% of EGHoldings, which operates a 3.7 mmta LNG production facility. In accordance with agreements related to the processing of third-party Alen Unit gas at EGHoldings, additional equity was issued to an equity partner, which is an E.G. government entity, during the fourth quarter of 2021, thereby reducing our ownership interest in EGHoldings from 60% to 56%. EGHoldings sells LNG produced from Alba field under a 3.4 mmta sales and purchase agreement. Under the current agreement, which runs through 2023, the purchaser takes delivery of the LNG on Bioko Island, with pricing linked principally to the Henry Hub index. EGHolding's gross sales of LNG from this production facility totaled approximately 2 mmta in 2021.

The processing of third-party gas from the Alen field through the existing Alba Plant LPG processing plant and the EGHoldings LNG production facility began in February 2021. This is the initial step in creating a proposed E.G. gas hub, which would process additional regional third-party gas. Alba Plant LLC and EGHoldings process the Alen gas under a combination of a tolling fee and profit-sharing arrangement, the benefits of which are included in our respective share of income from equity method investments.

We also own 45% of AMPCO, which operates a methanol plant. AMPCO had gross sales totaling approximately 925 mt in 2021. Methanol production is sold to customers in Europe and the U.S.

## Reserves

Proved reserves are required to be disclosed by continent and by country if the proved reserves related to any geographic area, on an oil equivalent barrel basis, represent 15% or more of our total proved reserves. A geographic area can be an individual country, group of countries within a continent, or a continent. For additional detail on reserves, see Item 8. Financial Statements and Supplementary Data – **Supplementary Information on Oil and Gas Producing Activities**.

The following tables set forth estimated quantities of our total proved crude oil and condensate, NGLs and natural gas reserves based upon SEC pricing for the year-ended December 31, 2021.

| | Crude Oil and Condensate (mmbbl) | Natural Gas Liquids (mmbbl) | Natural Gas (bcf) | Total (mmboe) | Total (%) |
|---|---|---|---|---|---|
| **Proved Developed Reserves** | | | | | |
| U.S. | 332 | 135 | 998 | 634 | 58 % |
| E.G. | 26 | 17 | 439 | 115 | 10 % |
| Total proved developed reserves (*mmboe*) | 358 | 152 | 1,437 | 749 | 68 % |
| **Proved Undeveloped Reserves** | | | | | |
| U.S. | 209 | 65 | 448 | 348 | 31 % |
| E.G. | 3 | 1 | 27 | 9 | 1 % |
| Total proved undeveloped reserves (*mmboe*) | 212 | 66 | 475 | 357 | 32 % |
| **Total Proved Reserves** | | | | | |
| U.S. | 541 | 200 | 1,446 | 982 | 89 % |
| E.G. | 29 | 18 | 466 | 124 | 11 % |
| Total proved reserves *(mmboe)* | 570 | 218 | 1,912 | 1,106 | 100 % |
| Total proved reserves (%) | 52 % | 20 % | 28 % | 100 % | |

## Productive and Drilling Wells

For our United States and International segments, the following table sets forth gross and net productive wells, service wells and drilling wells as of December 31 for the years presented.

| | Productive Wells | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Oil | | Natural Gas | | Service Wells | | Drilling Wells | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| **2021** | | | | | | | | |
| U.S. | 5,375 | 2,452 | 1,554 | 633 | 147 | 16 | 5 | 3 |
| E.G. | — | — | 19 | 12 | — | — | — | — |
| Total | 5,375 | 2,452 | 1,573 | 645 | 147 | 16 | 5 | 3 |
| **2020** | | | | | | | | |
| U.S. | 5,225 | 2,302 | 1,592 | 648 | 198 | 21 | | |
| E.G. | — | — | 19 | 12 | — | — | | |
| Total | 5,225 | 2,302 | 1,611 | 660 | 198 | 21 | | |
| **2019** | | | | | | | | |
| U.S. | 4,984 | 2,195 | 1,550 | 615 | 204 | 20 | | |
| E.G. | — | — | 19 | 12 | — | — | | |
| Total[(a)] | 4,984 | 2,195 | 1,569 | 627 | 204 | 20 | | |

(a) Other International was removed from 2019 due to the sale of our U.K. business and our 15% non-operated interest in the Atrush block in Kurdistan. See Item 8. Financial Statements and Supplementary Data – **Note 5** to the consolidated financial statements for further information.

## Drilling Activity

Our drilling activity during the year ended December 31, 2021 was comparable with 2020, reflecting a continuation of production maintenance activity levels, yet lower than the 2019 level given the 2020 macro environment and the reduction in our capital budget to prioritize free cash flow generation over production growth. The table below sets forth the number of net productive and dry development and exploratory wells completed as of December 31 for the years represented, all of which reside in our United States segment.

| | December 31, | | |
|---|---|---|---|
| | 2021 | 2020 | 2019 |
| **Development Wells** | | | |
| Oil | 137 | 103 | 197 |
| Natural Gas | 9 | 15 | 28 |
| Dry | — | — | — |
| Total Development Wells | 146 | 118 | 225 |
| **Exploratory Wells** | | | |
| Oil | 19 | 30 | 57 |
| Natural Gas | 2 | 14 | 26 |
| Dry | 8 | — | 2 |
| Total Exploratory Wells | 29 | 44 | 85 |
| Total Development and Exploratory Wells | 175 | 162 | 310 |

## Acreage

We believe we have satisfactory title to our United States and International properties in accordance with standards generally accepted in the industry; nevertheless, we can be involved in title disputes from time to time that may result in litigation. In the case of undeveloped properties, an investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. Our title to properties may be subject to burdens such as royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the industry. In addition, our interests may be subject to obligations or duties under applicable laws or burdens such as net profits interests, liens related to operating agreements, development obligations or capital commitments under international production sharing contracts or exploration licenses.

The following table sets forth, by geographic area, the gross and net developed and undeveloped acreage held as of December 31, 2021.

| | Developed | | Undeveloped | | Developed and Undeveloped | |
|---|---|---|---|---|---|---|
| *(In thousands)* | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| U.S. | 1,327 | 987 | 175 | 145 | 1,502 | 1,132 |
| E.G. | 82 | 67 | — | — | 82 | 67 |
| Total | 1,409 | 1,054 | 175 | 145 | 1,584 | 1,199 |

In the ordinary course of business, based on our evaluations of certain geologic trends and prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future. If production is not established or we take no other action to extend the terms of the leases, undeveloped acreage listed in the table below could expire over the next three years. We plan to continue the terms of certain of these leases through operational or administrative actions. There are no material quantities of net proved undeveloped reserves assigned to expiring undeveloped acreage in the next three years.

| | Net Undeveloped Acres Expiring Year Ended December 31, | | |
|---|---|---|---|
| *(In thousands)* | **2022** | **2023** | **2024** |
| U.S. | 50 | 78 | 8 |
| E.G. | — | — | — |
| Total | 50 | 78 | 8 |

## Net Sales Volumes

At December 31, 2021, 2020 and 2019, Eagle Ford, Bakken and Oklahoma in the United States contained 15% or more of our total proved reserves. Production for these fields along with our production from fields containing less than 15% of our total proved reserves are presented in the table below.

| | December 31, | | |
|---|---|---|---|
| | 2021 | 2020 | 2019 |
| **Net Sales Volumes** | | | |
| ***Crude oil and condensate (mbbld)*** [(a)] | | | |
| *United States* | | | |
| Eagle Ford | 58 | 61 | 63 |
| Bakken | 74 | 79 | 86 |
| Oklahoma | 12 | 17 | 21 |
| Northern Delaware | 13 | 15 | 16 |
| Other U.S. | 4 | 5 | 4 |
| *Africa* | | | |
| E.G. | 11 | 13 | 15 |
| *Other International* [(b)] | — | — | 5 |
| Total | 172 | 190 | 210 |
| ***Natural gas liquids (mbbld)*** | | | |
| *United States* | | | |
| Eagle Ford | 15 | 18 | 22 |
| Bakken | 23 | 14 | 9 |
| Oklahoma | 17 | 20 | 22 |
| Northern Delaware | 5 | 5 | 6 |
| Other U.S. | 2 | 2 | 1 |
| *Africa* | | | |
| E.G. | 7 | 9 | 9 |
| Total | 69 | 68 | 69 |
| ***Natural gas (mmcfd)*** | | | |
| *United States* | | | |
| Eagle Ford | 97 | 121 | 130 |
| Bakken | 90 | 70 | 46 |
| Oklahoma | 147 | 177 | 210 |
| Northern Delaware | 32 | 41 | 36 |
| Other U.S. | 13 | 14 | 16 |
| *Africa* | | | |
| E.G. | 259 | 330 | 365 |
| *Other International* [(b)] | — | — | 6 |
| Total | 638 | 753 | 809 |
| ***Total sales volumes (mboed)*** | | | |
| *United States* | | | |
| Eagle Ford | 89 | 99 | 106 |
| Bakken | 112 | 105 | 103 |
| Oklahoma | 54 | 66 | 78 |
| Northern Delaware | 23 | 27 | 28 |
| Other U.S. | 8 | 9 | 8 |
| *Africa* | | | |
| E.G. | 61 | 77 | 85 |
| *Other International* [(b)] | — | — | 6 |
| Total | 347 | 383 | 414 |

(a) The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

(b) Other International sales include sales volumes for the U.K. and the Atrush block in Kurdistan, which were both sold in 2019. See Item 8. Financial Statements and Supplementary Data – **Note 5** to the consolidated financial statements for further information.

**Average Sales Price and Production Costs per Unit** are presented by geographic area.

| | December 31, | | |
|---|---|---|---|
| *(Dollars per unit)* | 2021 | 2020 | 2019 |
| **Average Sales Price per Unit** [(a)] | | | |
| ***Crude oil and condensate (bbl)*** | | | |
| United States | $ 66.88 | $ 35.93 | $ 55.80 |
| E.G. | 57.46 | 28.36 | 48.99 |
| Other International [(b)] | — | — | 64.71 |
| Total | $ 66.25 | $ 35.39 | $ 55.54 |
| ***Natural gas liquids (bbl)*** | | | |
| United States | $ 28.89 | $ 11.28 | $ 14.22 |
| E.G. [(c)] | 1.00 | 1.00 | 1.00 |
| Other International [(b)] | — | — | 37.88 |
| Total | $ 26.19 | $ 9.97 | $ 12.46 |
| ***Natural gas (mcf)*** | | | |
| United States | $ 4.57 | $ 1.77 | $ 2.18 |
| E.G. [(c)] | 0.24 | 0.24 | 0.24 |
| Other International [(b)] | — | — | 5.67 |
| Total | $ 2.81 | $ 1.10 | $ 1.33 |
| **Average Production Costs per Unit** [(d)] | | | |
| United States | $ 9.99 | $ 8.40 | $ 9.08 |
| E.G. | 2.48 | 2.16 | 2.34 |
| Other International [(b)] | — | — | 30.42 |
| Total | $ 8.66 | $ 7.15 | $ 8.03 |

(a) Excludes gains or losses on commodity derivative instruments.

(b) Other International sales include sales volumes for the U.K. and the Atrush block in Kurdistan, which were both sold in 2019. See Item 8. Financial Statements and Supplementary Data ─ **Note 5** to the consolidated financial statements for further information.

(c) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO and/or EGHoldings, which are equity method investees. We include our share of income from each of these equity method investees in our International segment.

(d) Taxes other than income (such as production, severance and property taxes) are excluded; however, shipping and handling as well as other operating expenses are included in the production costs used in this calculation. See Item 8. Financial Statements and Supplementary Data – **Supplementary Information on Oil and Gas Producing Activities** ─ Results of Operations for Oil and Gas Production Activities for more information regarding production costs.

## Marketing

Our reportable operating segments include activities related to the marketing and transportation of substantially all of our crude oil and condensate, NGLs and natural gas. These activities include the transportation of production to market centers, the sale of commodities to third parties and the storage of production. We balance our various sales, storage and transportation positions in order to aggregate volumes to satisfy transportation commitments and to achieve flexibility within product types and delivery points. Such activities can include the purchase of commodities from third parties for resale.

## Major Customers

We are exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy-related industries. The creditworthiness of customers and other counterparties is subject to continuous review, and includes the use of master netting agreements, where appropriate.

Customers and their respective affiliates who accounted for 10% or more of our total commodity sales were as follows:

| | December 31, 2021 | 2020 | 2019 |
|---|---|---|---|
| **Percentage of Total Commodity Sales** | | | |
| Marathon Petroleum Corporation | 17 % | 13 % | 13 % |
| Valero Marketing and Supply | 10 % | N/A | 11 % |
| Koch Resources LLC | N/A | 12 % | 13 % |
| Shell Trading | N/A | N/A | 10 % |

### Gross Delivery Commitments

We have committed to deliver gross quantities of crude oil and condensate, NGLs and natural gas to customers under a variety of contracts. As of December 31, 2021, the contracts for fixed and determinable quantities were at variable, market-based pricing and related primarily to the following commitments:

| | 2022 | 2023 | 2024 | Thereafter | Commitment Period Through |
|---|---|---|---|---|---|
| **Eagle Ford** | | | | | |
| Crude and condensate *(mbbld)* | 31 | — | — | — | 2022 |
| Natural gas *(mmcfd)* | 128 | 52 | 12 | 7 | 2025 |
| **Bakken** | | | | | |
| Crude and condensate *(mbbld)* | 13 | 10 | 10 | 5 - 10 | 2027 |
| **Other United States** | | | | | |
| Natural gas *(mmcfd)* | 1 | — | — | — | 2022 |

All of these contracts provide the option of delivering third-party volumes or paying a monetary shortfall penalty if production is inadequate to satisfy our commitment. In addition to the contracts discussed above, we have entered into numerous agreements for transportation and processing of our equity production. Some of these contracts have volumetric requirements which could require monetary shortfall penalties if our production is inadequate to meet the terms.

### Competition

Competition exists in all sectors of the oil and gas industry and we compete with major integrated and independent oil and gas companies, national oil companies, and to a lesser extent, companies that supply alternative sources of energy. We compete, in particular, for the acquisition of oil and natural gas leases and other properties, in the exploration for and development of new reserves, the marketing and delivery of our production into worldwide commodity markets and for the labor and equipment required for exploration and development of those properties. Principal methods of competing include geological, geophysical and engineering research and technology, experience and expertise, economic analysis in connection with portfolio management and safely operating oil and gas producing properties. See **Item 1A. Risk Factors** for discussion of specific areas in which we compete and related risks.

### Government Regulations

Our businesses are subject to numerous laws and regulations, including those related to oil and gas exploration and production and to the protection of health, environment and safety. New laws have been enacted or are otherwise being considered and regulations are being adopted by various regulatory agencies on a continuing basis and the costs of compliance with these new laws and regulations can only be broadly appraised when their implementation becomes more defined. However, the current federal administration has indicated its intent to increase regulatory oversight of oil and gas activity specifically, and to put climate change at the forefront of its policy initiatives. We expect these policies to be wide-ranging and include executive branch action to address climate change and accelerate development of renewable resources.

The current administration already issued a number of executive and temporary orders and policy changes that address broad ranging issues including climate change, oil and gas activities on federal lands, infrastructure and environmental justice. These orders and policy changes may affect the issuance of permits and/or agency approvals. If permits and approvals are not issued, or if unfavorable restrictions or conditions are imposed on our drilling activities due to these orders or policy changes, we may not be able to conduct our operations as planned. As public policy changes are commonplace, we are unable to predict the future cost or impact of compliance. At this time, applicability of the executive temporary orders and policy changes appear to largely exclude tribal lands and we do not expect that any of these laws and regulations will affect our operations materially differently than they would affect other companies with similar operations, size and financial strength. Amendments or extensions along with implementation of the announced policy positions and initiatives that flow from these orders may have a material adverse impact on our business.

We also expect continued introduction of legislation on issues that may impact our business including financial disclosures, ESG related disclosures, COVID-19 relief, tax matters, exports of crude oil and LNG and access to capital.

The administration's "Whole of Government" approach to climate change has also resulted in the announcement and proposal of a number of regulatory initiatives. Those with the most potential to impact our industry include expected regulations from the EPA, the BLM, the U.S. Fish and Wildlife Service and the SEC. State governments where we operate are also considering making proposals to address climate change. While there are not currently climate-related regulations proposed or pending that we believe will result in material capital, operating, tax or other costs to the business at this time, such regulations could be proposed and/or passed into law in 2022 or beyond. Other regulations currently in place could be withdrawn and replaced with more stringent requirements in 2022 or beyond.

The Health, Environmental, Safety and Corporate Responsibility Committee of our Board of Directors is responsible for overseeing our position on public issues, including environmental, health and safety matters. Our Corporate Health, Environment, Safety and Security organization is responsible for ensuring that our operating organizations maintain environmental compliance systems that support and foster our compliance with applicable laws and regulations. Committees comprised of certain of our officers review our overall performance associated with various environmental compliance programs. We also have a Corporate Emergency Response Team that oversees our response to any major environmental or other emergency incident involving us or any of our properties.

*Environmental Remediation and Waste Management*

Our business is subject to laws relating to remediation of environmental pollution and the storage, handling and disposal of waste. These laws, and their implementing regulations and other similar state and local laws and rules, can impose certain operational controls for (i) minimization of pollution or recordkeeping, (ii) monitoring and reporting requirements or (iii) other operational or siting constraints on our business. These controls result in costs to remediate releases of regulated substances, including crude oil and produced water, into the environment, or require costs to remediate sites to which we sent regulated substances for disposal. In some cases, these laws can impose strict liability for the entire cost of clean-up on any responsible party without regard to negligence or fault and impose liability on us for the conduct of others (such as prior owners or operators of our assets) or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them. We have incurred and will continue to incur capital, operating and maintenance and remediation expenditures as a result of environmental laws and regulations.

Waste regulations include those for management, storage, transportation and disposal. Additional or expanded regulations relating to oilfield waste may be adopted that potentially impact the costs of compliance, handling, management and availability of disposal options.

*Air and Climate Change*

Concerns about emissions of carbon dioxide, methane and other greenhouse gases and their role in climate change may affect us and other similarly situated companies operating in the oil and gas industry. Further, recent actions by the federal government have signaled an intent to take significant action to address climate change. In addition, legislative proposals to address some of these issues have already begun and we expect additional proposals under the current federal administration that may become law. Until such proposals or actions are in final form, we cannot fully evaluate potential impacts, but as part of our commitment to environmental stewardship and as required by law, we estimate and publicly report greenhouse gas emissions from our operations. We are also working to continuously improve the accuracy and completeness of these estimates. Moreover, we are making a concentrated effort to improve operational and energy efficiencies through resource and energy conservation. Finally, we have also undertaken initiatives to highlight our commitment to improving environmental performance, including introducing new quantitative goals for the near, medium and long-term time horizon across three core areas of focus: GHG intensity, methane intensity and gas capture. We have added a GHG emissions intensity target to our short-term incentive annual cash bonus scorecard to better reflect these initiatives.

Government entities and other groups have filed lawsuits in several states and other jurisdictions seeking to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the greenhouse gas emissions attributable to those fuels. The lawsuits allege damages as a result of global warming and the plaintiffs are seeking unspecified damages and abatement under various tort theories. Marathon Oil has been named as a defendant in several of these lawsuits, along with numerous other companies. Similar lawsuits may be filed in other jurisdictions. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the claims made against us are without merit and will not have a material adverse effect on our consolidated financial position, results of operations or cash flow.

As part of the U.S. Methane Emissions Reduction Plan, unveiled by the EPA in late 2021, the EPA proposed amendments to the New Source Performance Standards for the oil and gas industry that seek to reduce methane emissions from new and existing facilities. These rules are expected to be finalized in 2022. Further, the State of New Mexico is expected to consider and potentially implement legislation and regulation that seeks to reduce GHG emissions in the state. We also expect the BLM to propose additional royalties on methane emissions and regulations designed to limit venting and flaring.

The EPA finalized a more stringent NAAQS for ozone in October 2015. States that contain any areas designated as non-attainment, and any tribes that choose to do so, will be required to complete development of implementation plans in the 2021-2022 time frame. The EPA may in the future designate additional areas as non-attainment, including areas in which we operate. In December 2020, EPA finalized a rule to retain the 2015 standard without revision. The current administration has requested nominations for scientific experts to staff an Ozone Panel for the purpose of providing scientific advice regarding a reconsideration of the ozone standard. The implementation of the 2015 standard, or the promulgation of a future more stringent standard, may result in an increase in costs for emission controls and requirements for additional monitoring and testing, as well as a more cumbersome permitting process. Although there may be an adverse financial impact (including compliance costs, potential permitting delays and increased regulatory requirements) associated with this revised regulation, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the present uncertainty regarding any additional measures and how they will be implemented.

*Hydraulic Fracturing*

Hydraulic fracturing is a commonly used process that involves injecting water, sand and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. Our business uses this technique extensively throughout our operations. Hydraulic fracturing has been regulated at the state and local level through permitting and compliance requirements.

The federal administration previously included as part of its platform actions that could amount to a de facto ban on hydraulic fracturing on federal lands and the EPA and other federal agencies, including the BLM, have previously made proposals that, if implemented, could either restrict the practice of hydraulic fracturing or subject the process to further regulation (and there is some question as to whether this could extend to tribal lands). Further, state and local-level initiatives may be proposed in regions with substantial shale resources to further regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing. Although there may be an adverse financial impact (including compliance costs, potential permitting delays and increased regulatory requirements) associated with these initiatives, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the present uncertainty regarding any additional measures and how they will be implemented.

*Water*

In 2014, the EPA and the U.S. Army Corps of Engineers published proposed regulations which expand the surface waters that are regulated under the federal CWA and its various programs. While these regulations were finalized largely as proposed in 2015, the rule was stayed by the courts pending a substantive decision on the merits. In October 2019, EPA and the Army Corps of Engineers issued a final rule that repealed the 2015 regulations and reinstated the agencies' narrower pre-2015 scope of federal CWA jurisdiction. In January 2020, EPA and the Army Corps of Engineers promulgated a new WOTUS definition that provided a narrower scope of federal CWA jurisdiction than contemplated under the 2015 WOTUS definition, while also providing for greater predictability and consistency of federal CWA jurisdiction. That rule was published in April 2020. EPA and U.S. Army Corps of Engineers received the U.S. District Court of Arizona's August 30, 2021 order vacating and remanding the 2020 Navigable Waters Rule. In light of the order, the agencies halted implementation of the 2020 rule and are interpreting "waters of the U.S." consistent with the pre-2015 regulatory scheme until further notice. On December 7, 2021, the EPA and Army Corps of Engineers published a proposed rule revising the definition of "waters of the U.S." by repealing the Navigable Waters Protection Rule and codifying a definition that reflects the pre-2015 regulatory regime, but with notice of intention to implement the "significant nexus" standard more closely with the 2015 rule.

If the current administration interprets WOTUS jurisdiction to be similar in scope to the 2015 rule, the expansion of CWA jurisdiction will result in additional costs of compliance as well as increased monitoring, recordkeeping and recording for some of our facilities.

*Other Oil and Gas Regulations*

The U.S. Fish & Wildlife Service has undertaken actions to rescind, revise or reinstate a number of wildlife-related regulations that relate to protection of endangered species and their habitats. Additional actions in this area are expected and can result in additional costs of compliance, as well as operational delays or siting challenges.

The BLM previously finalized regulations in 2016 and 2018 to regulate venting and flaring on lands regulated by the BLM, but those regulations were subsequently vacated by federal courts and the matters are being appealed. The current federal administration could re-issue similar or more stringent regulations and future regulations could result in additional costs of compliance, as well as increased monitoring, recordkeeping and recording for some of our wells and facilities.

For a discussion of environmental capital expenditures and costs of compliance for air, water, solid waste and remediation matters, see **Item 3. Legal Proceedings** and **Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies**.

For additional information, see **Item 1A. Risk Factors**.

## Trademarks, Patents and Licenses

We currently hold U.S. and foreign patents. Although in the aggregate our trademarks and patents are important to us, we do not regard any single trademark, patent, or group of related trademarks or patents as critical or essential to our business as a whole.

## Human Capital Management

*Oversight and Management*

We believe talent is one of the critical capabilities foundational to delivering on our corporate strategy. Intentional human capital management strategies enable us to attract, develop, retain and reward our dedicated employees. Marathon Oil believes in creating a safe, clean and ethical environment where employees feel empowered to make a difference in support of our business objectives and strategies. Our Vice President of Human Resources has leadership accountability for our workforce management policies and programs and reports directly to our CEO. She reviews quarterly talent data with our Executive Committee to assess the talent landscape and ensure measurement and accountability for human capital outcomes. Our Board provides oversight to our human capital management strategies as an integral part of our overall Enterprise Risk Management process. Due to the importance of our workforce capabilities, the Board receives updates on our human capital management measures as topical matters arise, such as talent as an enterprise risk, employee engagement, succession, Health, Environment and Safety (HES) and corporate social responsibility. Please visit *marathonoil.com/sustainability* for information on all dimensions of our corporate social responsibility.

*Our Culture*

We believe in fostering an inclusive culture to ensure the strength and resilience of our business. Respectful relationships are core to our culture. Our Code of Business Conduct, which applies to our directors, officers, employees and other parties when they are acting on behalf of Marathon Oil, includes specific sections on Diversity, Equality and Inclusion, as well as Mutual Respect. These sections include an emphasis on fostering an inclusive work environment and making hiring, promotion and disciplinary decisions based on relevant qualifications, merit, performance and similar job-related factors. Our diversity of people, experiences and ideas provides us with a business advantage. We are committed to fair and nondiscriminatory hiring and to celebrating the diversity of our workforce.

*Our Talent Landscape*

As of December 31, 2021, we had 1,531 active, full-time employees worldwide. Approximately 71% of our full-time workforce was based in the United States with 29% in Equatorial Guinea. Through recruiting, training, workforce integration, education and vocational programs, we strive to have a workforce reflective of the areas in which we operate. In 2021 and as a result of intentional nationalization efforts, 93% of our Marathon EG Production Limited (MEGPL), workforce was Equatoguinean.

For the U.S. workforce, our average tenure for full-time employees was 8 years, with 32% of our full-time population having 10 or more years of experience. As of December 31, 2021, women and people of color accounted for 33% and 30% of our U.S. full-time workforce, respectively. We encourage diversity, equity and inclusion and cultivate our collaborative team environment by making training courses on diversity and inclusive leadership available to all employees. We support Employee Resource Groups (ERGs) to promote diverse perspectives, encourage networking and allow continuous development activities.

Additionally, we implemented a new workforce flexibility program in 2021 while preserving our collaborative and One Team culture and providing broader options for our employees to better manage their career, work-life balance and overall well-being. Our office move to our new headquarters in late 2021 provided a unique opportunity to align our work environment to our vision, strategy and values, and capture the full potential of the One Team mind set: the integration of people, technology and innovation across all assets and functions. We also implemented a mental well-being initiative in 2021, which focused on educating and empowering our employees to talk about mental well-being and promoting the resources available to them.

Recognizing the cyclical nature of our business and the dynamic talent demands, we conduct a proactive risk analysis annually as part of our Enterprise Risk Management process, including a multi-year view of any potential talent risks to ensure we are prepared to respond to the macro- environment while setting ourselves up for long-term success. We fully leverage our common asset team organizational structure to drive knowledge sharing, collaboration and talent deployment across these teams resulting in efficiency gains and enhanced execution. Our partners and contractors are an essential element to our business and we follow a well-defined, rigorous evaluation process to ensure the partners we select uphold our expectations and core values. We utilize a managed service provider to oversee efficient administration, equitable treatment and compliance auditing of our contingent labor workforce.

*Health, Environment and Safety*

We believe safety is a core value and engrained in all aspects of our business. We uphold our safety and health culture by attracting, developing and retaining individuals and partners who share our commitment to operational excellence. Marathon Oil’s leadership establishes clear expectations to all personnel to comply with internal and external safety and health requirements. Furthermore, our HES values are embedded within our culture and the support we provide to our employees. We provide and require job specific HES training for our employees and full-time contractors as part of our Responsible Operations Management Systems (ROMS), which is a comprehensive operations integrity management system. This training includes stop the job authority extended to all employees and contractors in the event of a potential safety risk or environmental impact.

We leverage our collective talent and seek diverse employee perspectives to address complex issues and events through the use of multi-functional teams and committees, such as our internal Centralized Emergency Response Team (CERT) and Emissions Management Committee (EMC). Specifically, our comprehensive response to COVID-19 leaned heavily on our CERT team and our business continuity plans to protect both our workforce and sustain the essential services that our company provides. The EMC prioritizes GHG and methane emissions reduction opportunities across our enterprise and ensures appropriate funding is in place as part of our overall capital allocation process. Our commitment to addressing the dual challenge of meeting the world’s growing energy demands while also taking action on climate change is evidenced by GHG intensity featuring prominently as a metric linked directly to compensation outcomes.

Our values to collaborate, take ownership, be bold and deliver results enable us to excel, but that’s only possible if our workforce is safe. We actively look out for each other, maintain a safe work environment, continuously improve our procedures and train our workforce. Marathon Oil utilizes ROMS to manage risk and strives for a safe, healthy and secure workplace where all those involved can work free of injury and illness. Our Total Recordable Injury Rate (TRIR) is one of the metrics we use to measure our success in providing a safe working environment and is linked directly to compensation outcomes. Marathon strives to only partner with contractors who share our same commitment to safety and environmental impact. We carefully evaluate contractors through a rigorous supply chain process to verify they possess all necessary safety and health programs to execute work in a manner that meets our expectations.

*Benefits*

We attract and retain talent by offering benefit programs that are competitive and comprehensive. These programs create flexibility that allows employees to develop a meaningful career and overall well-being for themselves and their families. In 2021, we increased our family leave to create additional optionality for a greater portion of our employees to better manage their career and commitments at home. Our goal is to support employees with benefit programs that are consistent with our company's vision and strategies. We align the value of the benefit programs to the local markets where we compete for talent, along with the broader oil and gas industry. We believe effective communication around our benefit programs helps ensure we understand employees' perceptions and values around our benefits and that our employees understand the breadth and value of the benefits provided.

*Compensation*

Our success is based on financial performance and operational results, and we believe that our compensation program is an important driver of that success. The primary objectives of our programs are to pay for performance, encourage long-term stockholder value and pay competitively. To accomplish this, our compensation program is designed to reward employees for their performance and motivate them to continue to perform at a high level through both absolute feedback and relative performance assessment. The annual cash bonus is our short-term incentive for eligible employees, which reinforces both corporate and individual annual performance and prioritizes both financial and operational metrics. Eligible employees may also receive long-term incentives in the form of restricted stock awards that vest over multiple years to support retention and aligns employee interests with those of our stockholders, by driving value at the enterprise level. We provide market-competitive pay levels to attract and retain the best talent. We regularly benchmark each component of our pay program, including our benefit programs against our peers and a broader subset of the oil and gas industry, to ensure we remain competitive. See the "Compensation Discussion and Analysis" section of our Annual Proxy for information on our Executive Officers.

*Talent Development*

We invest in talent processes that drive high performance. We take a multi-pronged approach to organizational learning, which is driven through our centralized on-demand development hub and informed by our enterprise-wide talent assessment process. Our organizational learning approach blends online, on-the-job and classroom training with 360 assessments and leadership coaching to ensure all employees receive the feedback, tools and time they need to reach their fullest potential. Continuous leadership development is offered to all leaders throughout the year and content is intentionally focused on learning objectives. These programs range from new manager trainings to executive-level business simulations.

We review talent across the enterprise, measuring both technical and leadership capabilities. We leverage these talent assessments to identify critical skill gaps, guide critical skills trainings and ensure the effective deployment of talent. Our talent planning processes are aligned and consistent across the organization to ensure top talent occupies our most critical roles. Our succession process is designed to ensure we have identified the experiences and exposures needed to set employees up for success in future senior leadership roles. In 2021, we launched a general mentoring program, which focused on increasing communication, connection and trust to advance our company's culture. We also continued our Board mentoring program, which pairs senior leaders with directors.

### Information About our Executive Officers

The executive officers of Marathon Oil and their ages as of February 1, 2022, are as follows:

| | | |
|---|---|---|
| Lee M. Tillman | 60 | Chairman, President and Chief Executive Officer |
| Dane E. Whitehead | 60 | Executive Vice President—Chief Financial Officer |
| Patrick J. Wagner | 57 | Executive Vice President—Corporate Development and Strategy |
| Mike Henderson | 52 | Executive Vice President—Operations |
| Kimberly O. Warnica | 48 | Senior Vice President—General Counsel and Secretary |
| Gary E. Wilson | 60 | Vice President, Controller and Chief Accounting Officer |

Mr. Tillman was appointed by the board of directors as chairman of the board effective February 1, 2019. In August 2013, he was appointed as president and chief executive officer. Prior to this appointment, Mr. Tillman served as vice president of engineering for ExxonMobil Development Company (a project design and execution company), where he was responsible for all global engineering staff engaged in major project concept selection, front-end design and engineering. Between 2007 and 2010, Mr. Tillman served as North Sea production manager and lead country manager for subsidiaries of ExxonMobil in Stavanger, Norway. Mr. Tillman began his career in the oil and gas industry at Exxon Corporation in 1989 as a research engineer and has extensive operations management and leadership experience.

Mr. Whitehead was appointed executive vice president and chief financial officer in March 2017. Prior to this appointment, Mr. Whitehead served as executive vice president and chief financial officer of both EP Energy Corp. and EP Energy LLC (oil and natural gas producer) since May 2012. Between 2009 and 2012, Mr. Whitehead served as senior vice president of strategy and enterprise business development and a member of El Paso Corporation's executive committee. He joined El Paso Exploration & Production Company as senior vice president and chief financial officer in 2006. Before joining El Paso, Mr. Whitehead was vice president, controller and chief accounting officer of Burlington Resources Inc. (oil and natural gas producer), and formerly senior vice president and CFO of Burlington Resources Canada.

Mr. Wagner was appointed executive vice president of corporate development and strategy in November 2017 after having served as senior vice president of corporate development and strategy since March 2017, vice president of corporate development and interim chief financial officer since August 2016 and vice president of corporate development since April 2014. Prior to this appointment, he served as senior vice president, western business unit, for QR Energy LP (an oil and natural gas producer) and the affiliated Quantum Resources Management, which he joined in early 2012 as vice president, exploitation. Prior to that, Mr. Wagner was managing director in Houston for Scotia Waterous, the oil and gas arm of Scotiabank (an international banking services provider), from 2010 to 2012. Before joining Scotia, Mr. Wagner was vice president, Gulf of Mexico, for Devon Energy Corp. (an oil and natural gas producer), having joined Devon in 2003 as manager, international exploitation.

Mr. Henderson was appointed executive vice president, operations in March 2021, after having served as senior vice president, operations since May 2020, and as vice president of Regional Plays North since October 2017. Prior to that he held successive regional vice president roles since 2013 and managed operations in Oklahoma, North Dakota and Wyoming. Prior to his work in the resource plays, Mr. Henderson was development manager for international production operations in Equatorial Guinea and has been involved in a number of Marathon Oil's major projects in Equatorial Guinea, Norway and the Gulf of Mexico over the course of his career. Before joining Marathon Oil in 2004, he was employed by ExxonMobil, where he served in a number of operations and project management roles of increasing responsibility.

Ms. Warnica was appointed senior vice president, general counsel in January 2021 and secretary in March 2021. Prior to joining Marathon Oil she was executive vice president, general counsel, chief compliance officer and secretary at Alta Mesa Resources, Inc. (an exploration and production and midstream company), since 2018. Prior to Alta Mesa, Ms. Warnica served in several positions in the Marathon Oil legal department from 2016 to 2018, including assistant general counsel and assistant secretary. Prior to Marathon Oil, Ms. Warnica served as assistant general counsel and assistant secretary at Freeport-McMoRan Oil & Gas (formerly Plains Exploration and Production Company, an oil and gas production company). She started her career at Andrews Kurth LLP.

Mr. Wilson was appointed vice president, controller and chief accounting officer in October 2014. Prior to joining Marathon Oil, he served in various finance and accounting positions of increasing responsibility at Noble Energy, Inc. (a global exploration and production company) since 2001, including as director of corporate accounting from February 2014 through September 2014, director of global operations services finance from October 2012 through February 2014, director of controls and reporting from April 2011 through September 2012, and international finance manager from September 2009 through March 2011. In September 2021, Mr. Wilson informed us of his intention to retire from Marathon Oil effective March 1, 2022, following more than 7 years of service.

### Available Information

Our website is www.marathonoil.com. Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports and filings with the SEC are available free of charge on our website as soon as reasonably practicable after the reports are filed or furnished with the SEC. Information contained on our website is not incorporated into this Annual Report on Form 10-K or our other securities filings. Our filings are also available in hard copy, free of charge, by contacting us at 990 Town and Country Boulevard, Houston, Texas 77024-2217, Attention: Investor Relations Office, telephone: (713) 629-6600. The SEC also maintains a website (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Additionally, we make available free of charge on our website:

- our Code of Business Conduct (including our code of ethics for Senior Financial Officers);
- our Corporate Governance Principles; and
- the charters of our Audit and Finance Committee, Compensation Committee, Corporate Governance and Nominating Committee and Health, Environmental, Safety and Corporate Responsibility Committee.

## Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations. When considering an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in the foregoing pages under "Disclosures Regarding Forward-Looking Statements" and other information included and incorporated by reference into this Annual Report on Form 10-K.

### *Risks Associated with our Industry*

***A substantial decline in crude oil and condensate, NGLs and natural gas prices would reduce our operating results and cash flows and could adversely impact the carrying value of our assets.***

The markets for crude oil and condensate, NGLs and natural gas have been volatile and are likely to continue to be volatile in the future, causing prices to fluctuate widely. Our revenues and operating results are highly dependent on the prices we receive for our crude oil and condensate, NGLs and natural gas. Many of the factors influencing prices of crude oil and condensate, NGLs and natural gas are beyond our control. These factors include:

- worldwide and domestic supplies of and demand for crude oil and condensate, NGLs and natural gas;
- the cost of exploring for, developing and producing crude oil and condensate, NGLs and natural gas;
- the ability of the members of OPEC and certain non-OPEC members, such as Russia, to agree to and maintain production controls;
- the production levels of non-OPEC countries, including production levels in the shale plays in the United States;
- the level of drilling, completion and production activities by other exploration and production companies, and variability therein, in response to market conditions;
- political instability or armed conflict in oil and natural gas producing regions;
- changes in weather patterns and climate;
- natural disasters such as hurricanes and tornadoes;
- the price and availability of alternative and competing forms of energy, such as nuclear, hydroelectric, wind and solar;
- the effect of conservation efforts;
- epidemics or pandemics, including the ongoing novel coronavirus global pandemic, known as COVID-19;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxes; and
- general economic conditions worldwide.

The long-term effects of these and other factors on the prices of crude oil and condensate, NGLs and natural gas are uncertain. Historical declines in commodity prices have adversely affected our business by:

- reducing the amount of crude oil and condensate, NGLs and natural gas that we can produce economically;
- reducing our revenues, operating income and cash flows;
- causing us to reduce our capital expenditures, and delay or postpone some of our capital projects;
- requiring us to impair the carrying value of our assets;
- reducing the standardized measure of discounted future net cash flows relating to crude oil and condensate, NGLs and natural gas; and
- increasing the costs of obtaining capital, such as equity and short- and long-term debt.

***Estimates of crude oil and condensate, NGLs and natural gas reserves depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates. Any material changes in those conditions or other factors affecting those assumptions could impair the quantity and value of our reserves.***

The proved reserve information included in this Annual Report on Form 10-K has been derived from engineering and geoscience estimates. Estimates of crude oil and condensate, NGLs and natural gas were prepared, in accordance with SEC regulations, by our in-house teams of reservoir engineers and geoscience professionals and were reviewed and approved by our Corporate Reserves Group. Reserves were valued based on SEC pricing for the periods ended December 31, 2021, 2020 and 2019, as well as other conditions in existence at those dates. The table below provides the 2021 SEC pricing for certain benchmark prices:

| | 2021 SEC Pricing | |
|---|---|---|
| WTI crude oil *(per bbl)* | $ | 66.56 |
| Henry Hub natural gas *(per mmbtu)* | $ | 3.60 |
| Brent crude oil *(per bbl)* | $ | 69.47 |
| Mont Belvieu NGLs *(per bbl)* | $ | 28.57 |

If crude oil prices in the future average below prices used to determine proved reserves at December 31, 2021, it could have an adverse effect on our estimates of proved reserve volumes and the value of our business. Future reserve revisions could also result from changes in capital funding, drilling plans and governmental regulation, among other things.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of crude oil and condensate, NGLs and natural gas that cannot be directly measured. Estimates of economically producible reserves and of future net cash flows depend on a number of variable factors and assumptions, including:

- location, size and shape of the accumulation, as well as fluid, rock and producing characteristics of the accumulation;
- historical production from the area, compared with production from other analogous producing areas;
- the assumed impacts of regulation by governmental agencies;
- assumptions concerning future operating costs, taxes, development costs and workover and repair costs; and
- industry economic conditions, levels of cash flows from operations and other operating considerations.

As a result, different petroleum engineers and geoscientists, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of proved reserves and future net cash flows based on the same available data. Because of the subjective nature of such reserve estimates, each of the following items may differ materially from the estimated amounts:

- the amount and timing of production;
- the revenues and costs associated with that production; and
- the amount and timing of future development expenditures.

***Our operations may be adversely affected by pipeline, rail and other transportation capacity constraints.***

The marketability of our production depends in part on the availability, proximity and capacity of gathering and transportation pipeline facilities, rail cars, trucks and vessels. These facilities and equipment may be temporarily unavailable to us due to market conditions, regulatory reasons, mechanical reasons or other factors or conditions, and may not be available to us in the future on terms we consider acceptable, if at all. If any pipelines, rail cars, trucks or vessels become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport our crude oil and condensate, NGLs and natural gas, which could increase the costs and/or reduce the revenues we might obtain from the sale of our production. A pipeline shutdown could also have an impact on safety because it would require the use of additional trucks, rail cars and personnel. In addition, both the cost and availability of pipelines, rail cars, trucks, or vessels to transport our production could be adversely impacted by new state or federal regulations relating to transportation of crude oil. Any significant change in market, regulatory or other conditions affecting our access to, or the availability of, these facilities and equipment, including due to our failure or inability to obtain access to these facilities and equipment on terms acceptable to us or at all, could materially and adversely affect our business and, in turn, our financial condition and results of operations.

***If we acquire crude oil and natural gas properties, our failure to fully identify existing and potential problems, including title problems, to accurately estimate reserves, production rates or costs, or to effectively integrate the acquired properties into our operations could materially and adversely affect our business, financial condition and results of operations.***

We typically seek the acquisition of crude oil and natural gas properties and leases. Although we perform reviews of properties to be acquired in a manner that we believe is diligent and consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems, including title problems, nor may they permit us to become sufficiently familiar with the properties in order to fully assess possible deficiencies and potential problems. Properties and leases that we acquire may be subject to prior unregistered agreements, or transfers which have not been recorded or detected through our due diligence searches. If title to property associated with our projects is challenged, we may have to expend funds defending any such claims and our ownership interest therein may be detrimentally affected if we lose. Even when problems with a property are identified, we often assume environmental and other risks and liabilities in connection with acquired properties pursuant to the acquisition agreements. Moreover, there are numerous uncertainties inherent in estimating quantities of crude oil, NGLs and natural gas (as previously discussed), actual future production rates and associated costs with respect to acquired properties. Actual reserves, production rates and costs may vary substantially from those assumed in our estimates. In addition, an acquisition may have a material and adverse effect on our business and results of operations, particularly during the periods in which the operations of the acquired properties are being integrated into our ongoing operations or if we are unable to effectively integrate the acquired properties into our ongoing operations.

***Our operations may be affected by Native American treaty, title and other rights or claims.***

We are, and may in the future become, subject to various laws and regulations that apply to operators and other parties operating within the boundaries of Native American reservations in the United States. These laws and regulations may result in the imposition of certain fees, taxes, environmental standards, lease conditions or requirements to employ specified contractors or service providers. Any one of these requirements, or any delay in obtaining, or inability to obtain, the approvals or permits necessary to operate within the boundaries of Native American tribal lands, could adversely impact the Company’s operations and ability to explore and develop new and existing properties. Additionally, from time to time disputes may arise between state or federal governments and Native American tribes regarding title to lands within the United States or questions of sovereignty between the states and Native American tribes. For example, the State of North Dakota and three Indian tribes (the “Three Affiliated Tribes”) represented by the Bureau of Indian Affairs, have been involved in a dispute regarding the ownership of certain lands underlying the Missouri River and Little Missouri River (the “Disputed Land”) from which we currently produce. The United States Department of the Interior (“DOI”) has addressed the United States’ position with respect to this dispute several times over the past five years with conflicting opinions. Most recently, on February 4, 2022, the DOI issued an opinion (“M-Opinion”) concluding the DOI’s position that the Disputed Land is held in trust for the Three Affiliated Tribes. While the M-Opinion is binding on all agencies within the DOI, it is not legally binding on third parties, including Marathon Oil, or a court. Depending on the ultimate outcome of this title dispute, the Three Affiliated Tribes could challenge the validity of certain of our leases relating to a portion of the disputed land, and if such challenge were successful it could result in operational delays and additional costs, which could have a material and adverse effect on our business and results of operations. In addition, the process of addressing such claim or dispute, regardless of the outcome, could be expensive and time consuming and could result in delays which could have a material and adverse effect on our business, financial condition and results of operations.

***Future exploration and drilling results are uncertain and involve substantial costs.***

Drilling for crude oil and condensate, NGLs and natural gas involves numerous risks, including the risk that we may not encounter commercially productive reservoirs. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- inflation in exploration and drilling costs;
- fires, explosions, blowouts or surface cratering;
- lack of, or disruption in, access to pipelines or other transportation methods; and
- shortages or delays in the availability of services or delivery of equipment.

***We operate in a highly competitive industry, and many of our competitors are larger and have available resources in excess of our own.***

The oil and gas industry is highly competitive, and many competitors, including major integrated and independent oil and gas companies, as well as national oil companies, are larger and have substantially greater resources at their disposal than we do. We compete with these companies for the acquisition of oil and natural gas leases and other properties. We also compete with these companies for equipment and personnel, including petroleum engineers, geologists, geophysicists and other specialists, required to develop and operate those properties and in the marketing of crude oil and condensate, NGLs and natural gas to end-users. Such competition can significantly increase costs and affect the availability of resources, which could provide our larger competitors a competitive advantage when acquiring equipment, leases and other properties. They may also be able to use their greater resources to attract and retain experienced personnel.

***We are subject to various climate-related risks, including risks related to the transition to a lower-carbon economy and physical risks resulting from climate change.***

The following is a summary of potential climate-related risks that could adversely affect us:

<u>Policy and Legal Risks</u>. Policy risks include actions that seek to lessen activities that contribute to adverse effects of climate change or to promote adaptation to climate change. These policy actions could be accelerated by the change of party in control of Congress and the Presidency. Policy actions also may include restrictions or bans on oil and gas activities, like the January 2021 Presidential and Secretarial orders, and the potential banning of hydraulic fracturing, which could lead to write-downs or impairments of our assets. Legal risks include potential lawsuits claiming, among other things, failure to mitigate impacts of climate change, failure to adapt to climate change and the insufficiency of disclosure around material financial risks. The increasing attention to global climate change risks has created the potential for a greater likelihood of governmental investigations and private and public litigation, which could increase our costs or otherwise adversely affect our business.

<u>Market Risks</u>. Markets could be affected by climate change through shifts in supply and demand for certain commodities, including oil and gas and other products dependent on oil and gas. Lower demand for our oil and gas production could result in lower prices and lower revenues. Market risk also may take the form of limited access to capital as investors shift investments to industries and alternative energy industries that may be, or be perceived to be, less carbon-intensive. In addition, investment advisers, banks, and certain sovereign wealth, pension, and endowment funds recently have been promoting divestment of investments in fossil fuel companies and pressuring lenders to limit funding to companies engaged in the extraction, production, and sale of oil and gas. Some banks have made climate-related pledges for various initiatives, such as stopping the financing of Arctic drilling and coal companies. These initiatives by activists and banks could interfere with our business activities, operations and ability to access capital.

<u>Technology Risks</u>. Technological improvements or innovations that support the transition to a lower-carbon economic system may have a significant impact on us. The development and use of emerging technologies in renewable energy, battery storage, and energy efficiency may lower demand for oil and gas, resulting in lower prices and revenues. In addition, many automobile manufacturers have announced plans to shift production from internal combustion engine to electric powered vehicles, and some states and foreign countries have announced bans on sales of internal combustion engine vehicles beginning as early as 2025, which would reduce demand for oil.

<u>Reputation Risk</u>. Climate change is a potential source of reputational risk, which is tied to changing customer or community perceptions of an organization’s contribution to, or detraction from, the transition to a lower-carbon economy. These changing perceptions could lower demand for our oil and gas production, resulting in lower prices and lower revenues as consumers avoid carbon-intensive industries, and could also pressure banks and investment managers to shift investments and reduce lending as described above.

<u>Physical Risks</u>. Potential physical risks resulting from climate change may be event driven (including increased severity of extreme weather events, such as hurricanes, droughts, or floods) or longer-term shifts in climate patterns that may cause sea level rise or chronic heat waves. Potential physical risks may cause direct damage to assets and indirect impacts such as supply chain disruption and also could include changes in water availability, sourcing, and quality, which could impact drilling and completions operations. These physical risks could cause increased costs, production disruptions, and lower revenues and substantially increase the cost or limit the availability of insurance.

***Our offshore operations involve special risks that could negatively impact us.***

Offshore operations present technological challenges and operating risks because of the marine environment. Activities in offshore operations may pose risks because of the physical distance to oilfield service infrastructure and service providers. Environmental remediation and other costs resulting from spills or releases may result in substantial liabilities.

## Risks Related to Our Business Model and Capital Structure

***If we are unsuccessful in acquiring or finding additional reserves, our future crude oil and condensate, NGLs and natural gas production would decline, thereby reducing our cash flows and results of operations and impairing our financial condition.***

The rate of production from crude oil and condensate, NGLs and natural gas properties generally declines as reserves are depleted. Except to the extent we acquire interests in additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, optimize production performance or identify additional reservoirs not currently producing or secondary recovery reserves, our proved reserves may decline materially as crude oil and condensate, NGLs and natural gas are produced. Accordingly, to the extent we are not successful in replacing the crude oil and condensate, NGLs and natural gas we produce, our future revenues may decline. Creating and maintaining an inventory of prospects for future production depends on many factors, including:

- obtaining rights to explore for, develop and produce crude oil and condensate, NGLs and natural gas in promising areas;
- drilling success;
- the ability to complete projects timely and cost effectively;
- the ability to find or acquire additional proved reserves at acceptable costs; and
- the ability to fund such activity.

***If crude oil and condensate, NGLs and natural gas prices decrease, it could adversely affect the abilities of our counterparties to perform their obligations to us, which could negatively impact our financial results.***

We often enter into arrangements to conduct certain business operations, such as oil and gas exploration and production, or transportation of crude oil and condensate, NGLs and natural gas, with partners, co-working interest owners and other counterparties in order to share risks associated with those operations. In addition, we market our products to a variety of purchasers. If commodity prices decrease, some of our counterparties may experience liquidity problems and may not be able to meet their financial and other obligations to us. The inability of our joint venture partners or co-working interest owners to fund their portion of the costs under our joint venture agreements and joint operating agreements, or the nonperformance by purchasers, contractors or other counterparties of their obligations to us, could negatively impact our operating results and cash flows.

***If we are unable to complete capital projects at their expected costs and in a timely manner, or if the market conditions assumed in our project economics deteriorate, our business, financial condition, results of operations and cash flows could be materially and adversely affected.***

Delays or cost increases related to capital spending programs involving drilling and completion activities, engineering, procurement and construction of facilities (including improvements and repairs to our existing facilities) could adversely affect our ability to achieve forecasted internal rates of return and operating results. Delays in making required changes or upgrades to our facilities could subject us to fines or penalties as well as affect our ability to supply certain products we produce. Such delays or cost increases may arise as a result of unpredictable factors, many of which are beyond our control, including:

- denial of or delay in receiving requisite regulatory approvals and/or permits;
- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of components or construction materials;
- increased costs or operational delays resulting from shortages of water;
- adverse weather conditions, natural disasters or other events (such as equipment malfunctions, explosions, fires or spills) affecting our facilities, or those of vendors or suppliers;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- market-related increases in a project’s debt or equity financing costs; and
- nonperformance by, or disputes with, vendors, suppliers, contractors or subcontractors.

Any one or more of these factors could have a significant impact on our capital projects.

***Our level of indebtedness may limit our liquidity and financial flexibility.***

As of December 31, 2021, our total debt was $4.0 billion, and our next significant debt maturity is our $1.0 billion 4.4% senior unsecured notes due in 2027. Our indebtedness could have important consequences to our business, including, but not limited to, the following:

- we may be more vulnerable to general adverse economic and industry conditions;
- a portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes;
- our flexibility in planning for, or reacting to, changes in our industry may be limited;
- a financial covenant in our unsecured revolving credit facility (the "Credit Facility") stipulates that our total debt to total capitalization ratio will not exceed 65% as of the last day of any fiscal quarter, and if exceeded, may make additional borrowings more expensive and affect our ability to plan for and react to changes in the economy and our industry;
- we may be at a competitive disadvantage as compared to similar companies that have less debt; and
- additional financing in the future for working capital, capital expenditures, acquisitions or development activities, general corporate or other purposes may have higher costs and more restrictive covenants.

We may incur additional debt in order to fund our capital expenditures, acquisitions or development activities, or for general corporate or other purposes. A higher level of indebtedness increases the risk that our financial flexibility may deteriorate. Our ability to meet our debt obligations and service our debt depends on future performance. General economic conditions, crude oil and condensate, NGLs and natural gas prices, inflation, interest rates and financial, business and other factors will affect our operations and our future performance. Many of these factors are beyond our control and we may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings and equity financing may not be available to pay or refinance such debt. See Item 8. Financial Statements and Supplementary Data – **Note 18** to the consolidated financial statements for a discussion of debt obligations.

***Difficulty in accessing capital or a significant increase in our costs of accessing capital could adversely affect our business.***

A downgrade of our credit ratings or other influences, including third-party groups promoting the divestment of fossil fuel equities or pressuring financial services companies to limit or curtail activities with fossil fuel companies, could negatively impact our cost of capital and our ability to access the capital markets, increase the interest rate and fees we pay on our Credit Facility, and may limit or reduce credit lines with our bank counterparties. We receive credit ratings on our debt obligations from the major credit rating agencies in the United States. Due to the volatility in worldwide crude oil, NGL and natural gas prices in recent years, credit rating agencies review companies in the energy industry periodically, including us. At December 31, 2021, our corporate credit ratings were: Standard & Poor's Global Ratings Services BBB- (stable); Fitch Ratings BBB- (positive); and Moody's Investor Services, Inc. Baa3 (stable). The credit rating process is contingent upon a number of factors, many of which are beyond our control. We could also be required to post letters of credit or other forms of collateral for certain contractual obligations, which could increase our costs and decrease our liquidity or letter of credit capacity under our Credit Facility. Limitations on our ability to access capital could adversely impact the level of our capital spending budget, our ability to manage our debt maturities, or our flexibility to react to changing economic and business conditions.

***Our commodity price risk management activities may prevent us from fully benefiting from commodity price increases and may expose us to other risks, including counterparty risk.***

Global commodity prices are volatile. In order to mitigate commodity price volatility and increase the predictability of cash flows related to the marketing of our crude oil, NGLs and natural gas, we, from time to time, enter into crude oil, NGL and natural gas hedging arrangements with respect to a portion of our expected production. While hedging arrangements are intended to mitigate commodity price volatility, we may be prevented from fully realizing the benefits of price increases above the price levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging contracts fail to perform under the contracts. See **Item 7A. Quantitative and Qualitative Disclosures about Market Risk**.

***Many of our major projects and operations are conducted jointly with other parties, which may decrease our ability to manage risk.***

We often enter into arrangements to conduct certain business operations, such as oil and gas exploration and production with other parties in order to share risks associated with those operations. However, these arrangements also may decrease our ability to manage risks and costs, particularly where we are not the operator. We could have limited influence over and control of the behaviors and performance of these operations. In addition, misconduct, fraud, bankruptcy, noncompliance with applicable laws and regulations or improper activities by or on behalf of one or more of our partners or co-working interest owners, or entities we have entered into arrangements with could have a significant negative impact on our business and reputation.

## Regulatory Compliance and International Operations Risks

***We may incur substantial capital expenditures and operating costs, and our production could be adversely affected, as a result of compliance with and changes in law, regulations or requirements or initiatives, including those addressing environmental, health, safety or security or the impact of global climate change, air emissions or water management, and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected.***

Our businesses are currently subject to numerous laws, regulations, executive orders and other requirements relating to the protection of the environment, including those relating to the discharge of materials into the environment such as the flaring of natural gas, waste management, pollution prevention, greenhouse gas emissions, including carbon dioxide and methane, and the protection of endangered species as well as laws, regulations and other requirements relating to public and employee safety and health and to facility security.

The current administration issued a number of executive and temporary orders that address broad ranging issues including climate change, oil and gas activities on federal lands, infrastructure and environmental justice. At this time, applicability of the actions taken by the new administration appear to largely exclude tribal lands and we do not believe that these executive and temporary orders currently in effect will have a material adverse impact on our business. Amendments or extensions along with implementation of the announced policy positions and initiatives that flow from these orders may have a material adverse impact on our business.

Additionally, states in which we operate may: impose additional regulations legislation, or requirements, such as the proposed Volatile Organic Compound emission rules in New Mexico; begin initiatives addressing the impact of global climate change, air emissions or water management; or we may become subject to additional regulations based on questions of sovereignty between the states and Native American tribes. We have incurred and may continue to incur capital, operating and maintenance and remediation expenditures as a result of these laws, regulations and other requirements or initiatives that are being considered or otherwise implemented. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products, our operating results could be adversely affected. The specific impact of these laws, regulations and other requirements may vary depending on a number of factors, including the age and location of operating facilities and production processes. We may also be required to make material expenditures to modify operations, install pollution control equipment, perform site clean-ups or curtail operations that could materially and adversely affect our business, financial condition, results of operations and cash flows. We may become subject to liabilities that we currently do not anticipate in connection with new, amended or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination. In addition, any failure by us to comply with existing or future laws, regulations and other requirements could result in civil penalties or criminal fines and other enforcement actions against us. For example, in January 2020, we received a Notice of Violation from the EPA related to the Clean Air Act. We have received an initial draft consent decree from the EPA containing certain proposed injunctive terms relating to this enforcement action, and are actively negotiating the terms of the consent decree at this time. The enforcement actions will likely result in monetary sanctions and injunctive terms, which may increase our development costs, operating costs or both. Given the uncertainty in matters such as these, we are unable to predict the ultimate outcome of this matter at this time.

The Biden administration has already taken steps to address climate change, and we expect actions like these to continue, including additional orders, laws or regulations that could affect our operations. Our operations result in greenhouse gas emissions. Currently, various legislative or regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane, and nitrous oxides) are in various phases of review, discussion or implementation in the U.S. Internationally, the United Nations Framework Convention on Climate Change finalized an agreement among 195 nations at the 21st Conference of the Parties in Paris with an overarching goal of preventing global temperatures from rising more than 2 degrees Celsius (the "Paris Agreement"). The agreement includes provisions that every country take some action to lower emissions. In November 2019, the U.S. served notice on the United Nations that it would withdraw from the Paris Agreement in 2020. In January 2021, on behalf of the U.S., President Biden rejoined the Paris Agreement, which requires signatory countries to set voluntary targets to reduce domestic emissions and create stricter goals, which may ultimately result in additional laws or regulations restricting our emissions of GHGs. New legislation, regulations or international agreements in the future could result in increased costs to operate and maintain our facilities, capital expenditures to install new emission controls at our facilities, and costs to administer and manage any potential greenhouse gas emissions or carbon trading or tax programs. These costs and capital expenditures could be material. Although uncertain, these developments could increase our costs, reduce the demand for crude oil and condensate, NGLs, and natural gas, and create delays in our obtaining air pollution permits for new or modified facilities.

***The potential adoption of federal, state and local legislative and regulatory initiatives related to hydraulic fracturing could result in increased compliance costs, operating restrictions or delays in the completion of oil and gas wells.***

Hydraulic fracturing is a commonly used process that involves injecting water, sand and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. Our business uses this technique extensively throughout our U.S. operations. Hydraulic fracturing has been regulated at the state and local level through permitting and compliance requirements. Various state and local-level initiatives in regions with substantial shale resources have been or may be proposed or implemented to further regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing. In 2015 the BLM issued a rule governing certain hydraulic fracturing practices on lands within their jurisdiction; however, this rule was rescinded in December 2017. In March 2020, the U.S. District Court for the Northern District of California upheld the rescission.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of crude oil and condensate, NGLs and natural gas, including from the shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs which could increase costs of our operations and cause considerable delays in acquiring regulatory approvals to drill and complete wells.

***The potential adoption of federal, state and local legislative and regulatory initiatives intended to address potential induced seismic activity in the areas in which we operate could result in increased compliance costs, operating restrictions or delays in the completion of oil and gas wells.***

The production of oil and gas inherently involves the generation of produced water and oil and gas waste. State and federal regulatory agencies have focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity. Separate and apart from the referenced potential connection between injection wells and seismicity, concerns have been raised that hydraulic fracturing activities may be correlated to anomalous seismic events. When caused by human activity, such events are called induced seismicity. Marathon operates produced water injection wells and contracts for disposal of oil and gas waste in injection wells operated by third parties. Additionally, Marathon uses hydraulic fracturing techniques throughout its U.S. operations.

The legal requirements related to the disposal of produced water by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern arises from recent seismic events near injection disposal wells that are used for the disposal by injection of produced water resulting from oil and natural gas activities. In March 2016, the United States Geological Survey identified New Mexico, Oklahoma and Texas as being among the states with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and natural gas extraction. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting and operating of produced water disposal wells. For example, in Texas, the Railroad Commission adopted rules in 2014 governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and natural gas in order to address these seismic activity concerns within the state. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. Another example includes the recent Seismic Event Mitigation Plan and Protocol announced by the New Mexico Oil Conservation Division in 2021, which requires monitoring and the potential curtailments or shut-ins of salt water disposal wells located within specified distances of certain seismic events. States may issue new orders or implement policies to temporarily shut down or to curtail the injection volumes of existing wells in the vicinity of seismic events. Legislative, regulatory and policy initiatives intended to address these concerns may result in additional levels of regulation or other requirements that could lead to operational delays, increase our operating and compliance costs or otherwise adversely affect our operations.

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by us or by third parties whom we may contract with to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal.

Any one or more of these developments may result in operational delays, increase our operating and compliance costs or otherwise adversely affect our operations.

***Political and economic developments, possible terrorist activities and changes in law or policy in the U.S. or global markets could adversely affect our operations and materially reduce our profitability and cash flows.***

Local political and economic factors in U.S. and global markets could have a material adverse effect on us. We are subject to the political, geographic and economic risks and possible terrorist or piracy activities or other armed conflict attendant to doing business within or outside of the U.S. There are also many risks associated with operations in E.G. including the possibility that the government may seize our property with or without compensation, may attempt to renegotiate or revoke existing contractual arrangements or may impose additional taxes or royalty burdens.

Changes in the U.S. or global political and economic environment or any U.S. or global hostility or the occurrence or threat of future terrorist attacks, or other armed conflict, could adversely affect the economies of the U.S. and other developed countries. A lower level of economic activity could result in a decline in energy consumption, which could cause our revenues and margins to decline and limit our future growth prospects. These risks could lead to increased volatility in prices for crude oil and condensate, NGLs and natural gas. In addition, these risks could increase instability in the financial and insurance markets and make it more difficult for us to access capital and to obtain the insurance coverage that we consider adequate. These risks could also cause damage to, or the inability to access, production facilities or other operating assets and could limit our service and equipment providers ability to deliver items necessary for us to conduct our operations.

Actions of governments through tax legislation or interpretations of tax law, and other changes in law, executive order and commercial restrictions could reduce our operating profitability, both in the U.S. and abroad. The U.S. government can prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries and will continue to do so in the future. Changes in U.S. or foreign laws could also adversely affect our results, including new regulations resulting in higher costs to comply with regulations and higher costs to transport our production by pipeline, rail car, truck or vessel or the adoption of government payment transparency regulations that could require us to disclose competitively sensitive commercial information or that could cause us to violate the non-disclosure laws of other countries.

## General Risks

***Our business, financial conditions and results of operations have been adversely affected and may continue to be adversely affected by the ongoing COVID-19 global pandemic.***

Any widespread outbreaks of contagious diseases have the potential to impact our business and operations. The ongoing novel coronavirus global pandemic, known as COVID-19, had a material adverse impact on our business, financial condition and results of operations in 2020 and the continued impact of COVID-19 could be material. The early effects of COVID-19 included a substantial decline in demand for crude oil, condensate, NGLs, natural gas and other petroleum hydrocarbons, along with a corresponding deterioration in prices. While demand for crude oil, condensate, NGLs, natural gas and other petroleum hydrocarbons significantly recovered as the COVID-19 pandemic evolved, we are unable to predict the future impact of COVID-19 on overall economic activity and the demand for, and pricing of, our products. COVID-19 could have a negative impact on our operations; impact the ability of our counterparties to perform their obligations; result in voluntary and involuntary curtailments, delays or cancellations of certain drilling activities; impair the quantity or value of our reserves; result in transportation and storage capacity constraints; cause shortages of key personnel, including employees, contractors and subcontractors; interrupt global supply chains; increase impairments and associated charges to our earnings; impact our cash on hand, uses of cash and cause a decrease to our financial flexibility and liquidity. In addition, the risks associated with COVID-19 have impacted and may continue to impact our workforce and the way we meet our business objectives. Due to concerns over health and safety, the vast majority of our corporate workforce worked remotely for a significant period of time early in the pandemic. We implemented a process for a phased return of employees to the office in late 2020 and during April 2021, the majority of our corporate workforce returned to the office. Working remotely did not significantly impact our ability to maintain operations, or cause us to incur significant additional expenses; however, we are unable to predict whether we will need to reinstitute these or other measures and if so, the duration or ultimate impact of these measures. The extent to which the ongoing COVID-19 pandemic will impact our business and our financial results will depend on future developments, which are highly uncertain and cannot be predicted.

As a result, at the time of this filing, it is not possible to predict the overall impact of COVID-19 on our business, liquidity, capital resources and financial results.

***Mandatory COVID-19 vaccination of employees could impact our workforce and lead to labor disruptions, which could have a material adverse effect on our business and results of operations.***

On September 9, 2021, President Biden announced plans for the federal Occupational Safety and Health Administration ("OSHA") to issue an Emergency Temporary Standard ("ETS") mandating that all employers with more than 100 employees ensure their workers are either fully vaccinated against COVID-19 or produce, on a weekly basis, a negative COVID test (the "vaccine-or-test mandate"). On November 5, 2021, OSHA issued the ETS, which required covered employers to comply with the vaccine-or-test mandate beginning January 4, 2022 or face substantial penalties for non-compliance. Multiple parties, including 27 states, initiated litigation to block the ETS. On January 13, 2022, the U.S. Supreme Court issued an emergency stay, which blocks the ETS from being enforced until the ETS works its way through the lower courts. Then, effective January 26, 2022, OSHA withdrew the ETS as an enforceable emergency temporary standard, but did not withdraw the ETS as a proposed rule. The ultimate outcome of this proposed rule and related litigation cannot be determined at this time. In addition to the proposed vaccine-or-test mandate, it is possible that additional mandates may be proposed or announced by foreign or local jurisdictions that could impact our workforce and operations, or the workforce and operations of our vendors.

Although we cannot predict with certainty the impact that the proposed vaccine mandate and any other related measures may have on our workforce and operations, or the workforce and operations of our vendors, these proposed mandates and any future mandates may result in increased operating costs, labor disruptions or employee attrition, which could be material. If we lose employees, it may be difficult to find replacement employees, and this could have an adverse effect on future revenues and costs, which could be material. Additional uncertainty could be caused by competing and potentially conflicting laws and regulations, such as the executive order issued by the Governor of Texas prohibiting vaccine mandates. Furthermore, these proposed measures may further disrupt the national supply chain, all of which could have a material adverse effect on our business, financial condition and results of operations.

***Our business could be negatively impacted by cyberattacks targeting our computer and telecommunications systems and infrastructure, or targeting those of our third-party service providers.***

Our business, like other companies in the oil and gas industry, has become increasingly dependent on digital technologies, including technologies that are managed by third-party service providers or other providers of goods or services to our industry on whom we directly or indirectly rely to help us collect, host or process information. Such technologies are integrated into our business operations and used as a part of our production and distribution systems in the U.S. and abroad, including those systems used to transport production to market, to enable communications and to provide a host of other support services for our business. Use of the internet and other public networks for communications, services and storage, including "cloud" computing, exposes all users (including our business) to cybersecurity risks.

While we and our third-party service providers commit resources to the design, implementation and monitoring of our information systems, there is no guarantee that our security measures will provide absolute security. Despite these security measures, we may not be able to anticipate, detect, or prevent cyberattacks, particularly because the methodologies used by attackers change frequently or may not be recognized until launched, and because attackers are increasingly using techniques designed to circumvent controls and avoid detection. We and our third-party service providers may therefore be vulnerable to security events that are beyond our control, and we may be the target of cyber-attacks, as well as physical attacks, which could result in information security breaches and significant disruption to our business. Our information systems and related infrastructure have experienced attempted and actual minor breaches of our cybersecurity in the past, but we have not suffered any losses or breaches which had a material effect on our business, operations or reputation relating to such attacks; however, there is no assurance that we will not suffer such losses or breaches in the future.

As cyberattacks continue to evolve, we may be required to expend significant additional resources to respond to cyberattacks, to continue to modify or enhance our protective measures, or to investigate and remediate any information systems and related infrastructure security vulnerabilities. Additionally, the continuing and evolving threat of cybersecurity attacks has resulted in evolving legal and compliance matters, including increased regulatory focus on prevention, which could require us to expend significant additional resources to meet such requirements. We may also be subject to regulatory investigations or litigation relating from cybersecurity issues.

***Our business may be materially adversely affected by negative publicity.***

From time to time, political and public sentiment with respect to, or impacts by, the oil and gas industry may result in adverse press coverage and other adverse public statements affecting our business. Additionally, though we believe we can achieve our voluntary company targets and goals, any failure to realize or perception of failure to realize voluntary targets or long-term goals, including GHG emissions targets, could lead to adverse press coverage and other adverse public statements affecting Marathon Oil. Adverse press coverage and other adverse statements, whether or not driven by political or public sentiment, may also result in investigations by regulators, legislators and law enforcement officials or in legal claims.

***Our operations are subject to business interruptions and casualty losses. We do not insure against all potential losses and therefore we could be seriously harmed by unexpected liabilities and increased costs.***

Our United States and International operations are subject to unplanned occurrences, including blowouts, explosions, fires, loss of well control, spills, tornadoes, hurricanes and other adverse weather, tsunamis, earthquakes, volcanic eruptions or nuclear or other disasters, labor disputes and accidents. These same risks can be applied to the third-parties which transport our products from our facilities. A prolonged disruption in the ability of any pipelines, rail cars, trucks, or vessels to transport our production could contribute to a business interruption or increase costs.

Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. These hazards could result in serious personal injury or loss of human life, significant damage to property and equipment, environmental pollution, impairment of operations and substantial losses to us. Various hazards have adversely affected us in the past, and damages resulting from a catastrophic occurrence in the future involving us or any of our assets or operations may result in our being named as a defendant in one or more lawsuits asserting potentially large claims or in our being assessed potentially substantial fines by governmental authorities. We maintain insurance against many, but not all, potential losses or liabilities arising from operating hazards in amounts that we believe to be prudent. Uninsured losses and liabilities arising from operating hazards could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows. Historically, we have maintained insurance coverage for physical damage including at times resulting business interruption to our major onshore and offshore facilities, with significant self-insured retentions. In the future, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for our insurance policies will change over time and could escalate. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage.

***Litigation by private plaintiffs or government officials or entities could adversely affect our performance.***

We currently are defending litigation and anticipate that we will be required to defend new litigation in the future. The subject matter of such litigation may include releases of hazardous substances from our facilities, privacy laws, contract disputes, title disputes, royalty disputes or any other laws or regulations that apply to our operations. In some cases the plaintiff or plaintiffs seek alleged damages involving large classes of potential litigants, and may allege damages relating to extended periods of time or other alleged facts and circumstances. If we are not able to successfully defend such claims, they may result in substantial liability. We do not have insurance covering all of these potential liabilities. In addition to substantial liability, litigation may also seek injunctive relief which could have an adverse effect on our future operations.

For instance, government entities and other groups have filed lawsuits in several states seeking to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the greenhouse gas emissions and other alleged harm attributable to those fuels. The lawsuits allege damages as a result of global warming and the plaintiffs are seeking unspecified damages and abatement under various theories. Marathon Oil has been named as a defendant in several of these lawsuits, along with numerous other companies. Similar lawsuits may be filed in other jurisdictions. Additionally, Marathon Oil has been named in various lawsuits alleging royalty underpayments in our domestic operations, and plaintiffs in some of these lawsuits are seeking class certification. We intend to vigorously defend ourselves against such claims. Although we have accrued for potential liabilities associated with these lawsuits, those accruals are based on currently available information and involve elements of judgment and significant uncertainties. Accordingly, actual losses may exceed our accruals or we could be required to accrue additional amounts in the future and these amounts could be material. The ultimate outcome and impact to us cannot be predicted with certainty, and we could incur substantial legal costs associated with defending these and similar lawsuits in the future.

## Item 1B. Unresolved Staff Comments

None.

## Item 3. Legal Proceedings

We are a defendant in a number of legal and administrative proceedings arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims, tax disputes and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

See Item 8. Financial Statements and Supplementary Data – **Note 26** to the consolidated financial statements for a description of such legal and administrative proceedings.

### *Environmental Proceedings*

The following is a summary of certain proceedings involving us that were pending or contemplated as of December 31, 2021, under federal and state environmental laws.

Government entities have filed lawsuits in several states seeking to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the greenhouse gas emissions and other alleged harm attributable to those fuels. The lawsuits allege damages as a result of global warming and the plaintiffs are seeking unspecified damages and abatement under various theories. Marathon Oil has been named as a defendant in several of these lawsuits, along with numerous other companies. Similar lawsuits may be filed in other jurisdictions. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the claims made against us are without merit and will not have a material adverse effect on our consolidated financial position, results of operations or cash flow.

As of December 31, 2021, we have sites across the country where remediation is being sought under environmental statutes, both federal and state, or where private parties are seeking remediation through discussions or litigation. Based on currently available information the accrued amount to address the clean-up and remediation costs connected with these sites is not material.

In January 2020, we received a Notice of Violation from the EPA related to the Clean Air Act. We have received an initial draft consent decree from the EPA containing certain proposed injunctive terms relating to this enforcement action, and are actively negotiating the terms of the consent decree at this time. The enforcement actions will likely result in monetary sanctions and injunctive terms, which may increase our development costs, operating costs or both. Given the uncertainty in matters such as these, we are unable to predict the ultimate outcome of this matter at this time. However, we do not believe these enforcement actions would have a material adverse effect on our consolidated financial position, results of operations or cash flow.

If our assumptions relating to these costs prove to be inaccurate, future expenditures may exceed our accrued amounts.

## Item 4. Mine Safety Disclosures

Not applicable.

## PART II

## Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The principal market on which Marathon Oil common stock is traded is the New York Stock Exchange ("NYSE"), and is traded under the trading symbol 'MRO'. As of January 31, 2022, there were 26,292 registered holders of Marathon Oil common stock.

***Dividends*** – Our Board of Directors intends to declare and pay dividends on Marathon Oil common stock based on our financial condition and results of operations, although it has no obligation under Delaware law or the restated certificate of incorporation to do so. In determining our dividend policy, the Board of Directors will rely on our consolidated financial statements. Dividends on Marathon Oil common stock are limited to our legally available funds.

***Issuer Purchases of Equity Securities*** – The following table provides information about purchases by Marathon Oil, during the quarter ended December 31, 2021, of equity securities that are registered by Marathon Oil pursuant to Section 12 of the Securities Exchange Act of 1934. As of December 31, 2021, we have $1.9 billion of authorization remaining under the share repurchase program.

| Period | Total Number of Shares Purchased[a] | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[b] | Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[b] |
|---|---|---|---|---|
| 10/01/2021 - 10/31/2021 | 9,976,809 | $ 15.92 | 9,959,789 | $ 1,161,719,576 |
| 11/01/2021 - 11/30/2021 | 10,178,355 | $ 16.49 | 10,177,722 | $ 2,373,902,569 |
| 12/01/2021 - 12/31/2021 | 25,409,775 | $ 15.63 | 25,409,775 | $ 1,976,852,884 |
| Total | 45,564,939 | $ 15.88 | 45,547,286 | |

(a) 17,653 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

(b) In January 2006, we announced a $2 billion share repurchase program. Our Board of Directors subsequently increased the authorization for repurchases under the program on multiple occasions, as detailed below, resulting in a cumulative authorization of $8.5 billion. This total authorized amount encompasses the entire lifecycle of the program, from 2006 - 2021, which includes share authorization approvals made prior to and subsequent of the spin-off of Marathon Petroleum Corporation in 2011.

The individual increases in the authorized share repurchase program were: $500 million in January 2007; $500 million in May 2007; $2 billion in July 2007; $1.2 billion in December 2013; $950 million in July 2019; $1.4 billion in November 2021.

As of December 31, 2021, we had repurchased 236 million common shares at a cost of approximately $6.5 billion, excluding transaction fees and commissions. Purchases under the program are made at our discretion and may be in either open market transactions, including block purchases, or in privately negotiated transactions using cash on hand, cash generated from operations, proceeds from potential asset sales or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination by the Board of Directors prior to completion. Shares repurchased as of December 31, 2021 were held as treasury stock.

## Item 6. [Reserved]

## Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

*Management's Discussion and Analysis provides a narrative on the Company's results of operations, financial condition and liquidity and capital resources on a historical basis and outlines the factors that have affected recent earnings, as well as those factors that are reasonably likely to affect future earnings. The following discussion and analysis should be read in conjunction with the information under Item 8. Financial Statements and Supplementary Data of this report and includes forward-looking statements that involve certain risks and uncertainties. See "Disclosures Regarding Forward-Looking Statements" (immediately prior to Part I) and* ***Item 1A. Risk Factors****.*

Each of our two reportable operating segments are organized by geographic location and managed according to the nature of the products and services offered.

- United States – explores for, produces and markets crude oil and condensate, NGLs and natural gas in the United States;
- International – produces and markets crude oil and condensate, NGLs and natural gas outside of the United States and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.

## Executive Overview

We are an independent exploration and production company, focused on U.S. resource plays: Eagle Ford in Texas, Bakken in North Dakota, STACK and SCOOP in Oklahoma and Northern Delaware in New Mexico. Our U.S. assets are complemented by our international operations in E.G. Our overall business strategy is to responsibly deliver competitive corporate return levels, free cash flow and cash returns to shareholders, all of which are sustainable and resilient through long-term commodity price cycles. We expect to achieve our business strategy by adherence to a disciplined reinvestment rate capital allocation framework that limits our capital expenditures relative to our expected cash flow from operations. Keeping our workforce safe, maintaining a strong balance sheet, responsibly meeting global energy demand with a focus on continuously improving environmental performance, serving as a trusted partner in our local communities and maintaining best in-class corporate governance standards are foundational to the execution of our strategy.

The risks associated with COVID-19 impacted our workforce and the way we meet our business objectives. Throughout the COVID-19 pandemic, we continue to leverage our emergency response protocols and business continuity plans to help manage our operations and workforce. Our corporate workforce worked remotely for a significant period of time when the pandemic began. In late 2020, we implemented a process for a phased return of employees to the office, and during April 2021, the majority of our corporate workforce returned to the office. Working remotely did not significantly impact our ability to maintain operations, allowed our field offices to operate without any disruption and did not cause us to incur significant additional expenses.

Key 2021 highlights include:

*Improved financial and operational results*

- The significant increases in realized prices for crude oil and condensate, NGLs and natural gas resulted in:
  - An increase of $2.5 billion in revenues from contracts with customers as compared to 2020
  - Increase in income from our equity method investments of $414 million as compared to 2020
    - Our equity investees' improved financial performance resulted in an increase of $243 million in income;
    - The prior year included impairments of $171 million related to one of our equity method investees, which was recorded in the same line item as income from our equity method investments; there were no such impairments in 2021
  - A net loss on commodity derivatives of $383 million, compared to a net gain of $116 million in 2020.
- Partially offsetting the higher prices were increases in production taxes, shipping and handling costs and loss on early extinguishment of debt
  - Production taxes increased $145 million; these taxes fluctuate in relation to the underlying commodity prices and volumes
  - Shipping and handling costs increased $131 million as certain of our midstream processing arrangements are percentage-of-proceeds contracts, with such processing costs increasing with the underlying commodity prices
  - The $121 million loss on early extinguishment of debt primarily represents the premium payments for early redemptions during 2021, consistent with our balance sheet enhancement strategy
- Our net income per share was $1.20 in 2021 as compared to a net loss per share of $1.83 last year.

- Cash provided by operating activities was $3.2 billion in 2021, an increase of $1.8 billion compared to 2020, in direct relation to the improvement in commodity prices and our improved financial performance
  - Our cash from operations totaled $1.1 billion in the fourth quarter of 2021

*Enhanced the balance sheet, increased return of capital to investors, preserved liquidity*

- Reduced total debt outstanding by fully redeeming $1.4 billion of senior notes during 2021
  - Our next significant long-term debt maturity is $1.0 billion due in 2027
  - All three primary credit rating agencies continue to rate us as investment grade
- Increased return of capital to investors by:
  - Repurchasing $724 million of our common stock (46 million shares) in 2021 via the share repurchase program
  - Distributing dividends totaling $141 million, an increase of $77 million from 2020
- Delivered on our commitment to capital discipline with full-year 2021 capital expenditures of $1.0 billion.
- Our $3.2 billion of full year 2021 cash provided by operating activities substantially funded our $1.4 billion debt redemptions, $1.0 billion capital expenditures, $724 million of share repurchases and $141 million of dividends
- Our $3.7 billion of liquidity at the end of the fourth quarter 2021 consists of an undrawn $3.1 billion Credit Facility and $580 million in cash.

*ESG Highlights and Initiatives*

- Second best safety performance since Marathon became an independent E&P, as measured by Total Recordable Incident Rate for employees and contractors
- Continued to reduce GHG emissions intensity (relative to 2019 baseline) and improved total company gas capture during 2021
- Announced new environmental objectives for GHG intensity, methane intensity, and natural gas capture that complement existing 2025 GHG intensity goal
- Updated the short-term incentive scorecard with a renewed focus on safety performance, environmental performance (GHG emissions intensity), capital and operating efficiency, capital discipline/free cash flow generation and financial/ balance sheet strength
- Continued Board of Directors enhancement with two new Directors and a new Lead Director during 2021, reflecting commitment to refreshment, independence and diversity

## Outlook

In February 2022, we announced a 2022 capital budget of $1.2 billion that prioritizes free cash flow generation over production growth, consistent with our disciplined capital allocation framework. We expect this maintenance-level capital budget will allow us to keep total company oil production in 2022 consistent with the oil production average from 2021.

The 2022 capital budget is weighted towards the four U.S. resource plays with approximately 75% allocated to the Eagle Ford and Bakken.

## Operations

The following table presents a summary of our sales volumes for each of our segments. Refer to the Results of Operations section for a price-volume analysis for each of the segments.

| **Net Sales Volumes** | **2021** | **Increase (Decrease)** | **2020** | **Increase (Decrease)** | **2019** |
|---|---|---|---|---|---|
| United States *(mboed)* | 286 | (7)% | 306 | (5)% | 323 |
| International *(mboed)*[(a)] | 61 | (21)% | 77 | (15)% | 91 |
| **Total *(mboed)*** | 347 | (9)% | 383 | (7)% | 414 |

(a) We closed on the sale of our interest in the Atrush block in Kurdistan in the second quarter of 2019 and our U.K. business in the third quarter of 2019. See Item 8. Financial Statements and Supplementary Data – **Note 5** to the consolidated financial statements for further information on dispositions.

***United States***

Net sales volumes in the segment were lower during the year ended December 31, 2021 due to lower capital investment, timing of wells to sales, natural decline and third-party midstream downtime. The decrease in capital investment is a direct result of the demand contraction, beginning in 2020 related to the global pandemic, coupled with our strategic goals of enhancing the balance sheet and return of capital to investors. The following tables provide additional details regarding net sales volumes, sales mix and operational drilling activity for our significant operations within this segment:

| **Net Sales Volumes** | **2021** | **Increase (Decrease)** | **2020** | **Increase (Decrease)** | **2019** |
|---|---|---|---|---|---|
| Equivalent Barrels *(mboed)* | | | | | |
| Eagle Ford | 89 | (10)% | 99 | (7)% | 106 |
| Bakken | 112 | 7 % | 105 | 2 % | 103 |
| Oklahoma | 54 | (18)% | 66 | (15)% | 78 |
| Northern Delaware | 23 | (15)% | 27 | (4)% | 28 |
| Other United States | 8 | (11)% | 9 | 13 % | 8 |
| **Total United States** | 286 | (7)% | 306 | (5)% | 323 |

| **Sales Mix - U.S. Resource Plays - 2021** | **Eagle Ford** | **Bakken** | **Oklahoma** | **Northern Delaware** | **Total** |
|---|---|---|---|---|---|
| Crude oil and condensate | 65% | 66% | 23% | 56% | 56% |
| Natural gas liquids | 17% | 20% | 32% | 21% | 22% |
| Natural gas | 18% | 13% | 45% | 23% | 22% |

| **Drilling Activity - U.S. Resource Plays** | **2021** | **2020** | **2019** |
|---|---|---|---|
| **Gross Operated** | | | |
| *Eagle Ford:* | | | |
| Wells drilled to total depth | 91 | 88 | 127 |
| Wells brought to sales | 117 | 87 | 146 |
| *Bakken:* | | | |
| Wells drilled to total depth | 72 | 63 | 73 |
| Wells brought to sales | 71 | 64 | 105 |
| *Oklahoma:* | | | |
| Wells drilled to total depth | — | 9 | 68 |
| Wells brought to sales | 8 | 13 | 69 |
| *Northern Delaware:* | | | |
| Wells drilled to total depth | — | 15 | 51 |
| Wells brought to sales | 7 | 19 | 54 |

***International***

Net sales volumes in the segment were lower during the year ended December 31, 2021 primarily due to natural decline. The following table provides details regarding net sales volumes for our operations within this segment:

| **Net Sales Volumes** | **2021** | **Increase (Decrease)** | **2020** | **Increase (Decrease)** | **2019** |
|---|---|---|---|---|---|
| Equivalent Barrels *(mboed)* | | | | | |
| Equatorial Guinea | 61 | (21)% | 77 | (9)% | 85 |
| United Kingdom[(a)] | — | — % | — | (100)% | 5 |
| Other International | — | — % | — | (100)% | 1 |
| **Total International** | 61 | (21)% | 77 | (15)% | 91 |
| **Equity Method Investees** | | | | | |
| LNG *(mtd)* | 2,941 | (31)% | 4,289 | (13)% | 4,933 |
| Methanol *(mtd)* | 1,046 | 3 % | 1,017 | (6)% | 1,082 |
| Condensate and LPG *(boed)* | 8,560 | (17)% | 10,288 | (7)% | 11,104 |

(a) During 2019, we closed on the sale of our U.K. business. See Item 8. Financial Statements and Supplementary Data – **Note 5** to the consolidated financial statements for further information.

## Market Conditions

Commodity prices are the most significant factor impacting our revenues, profitability, operating cash flows, the amount of capital we invest in our business, redemption of our debt, payment of dividends and funding of share repurchases. Commodity prices declined substantially in the first half of 2020 resulting from demand contraction related to the global pandemic and increased supply following OPEC's decision to increase production. A revised OPEC deal to reduce production was agreed early in the second quarter of 2020 and prices partially recovered through the end of the year. Beginning in December 2020 and continuing through 2021, commodity prices continued to increase due to rising oil demand as global economic activity increased. Higher commodity prices were also supported by ongoing OPEC petroleum supply limitations and weather events in 2021 that disrupted production. We continue to expect commodity price volatility given the global dynamics of supply and demand that exist in the market, including potential geopolitical events. See **Item 1A. Risk Factors** and **Item 7. Management's Discussion and Analysis of Financial Condition – Critical Accounting Estimates** for further discussion of how declines in these commodity prices could impact us.

***United States***

The following table presents our average price realizations and the related benchmarks for crude oil and condensate, NGLs and natural gas for 2021, 2020 and 2019.

| | 2021 | Increase (Decrease) | 2020 | Increase (Decrease) | 2019 |
|---|---|---|---|---|---|
| **Average Price Realizations**[(a)] | | | | | |
| Crude oil and condensate *(per bbl)*[(b)] | $ 66.88 | 86 % | $ 35.93 | (36)% | $ 55.80 |
| Natural gas liquids *(per bbl)*[(c)] | 28.89 | 156 % | 11.28 | (21)% | 14.22 |
| Natural gas *(per mcf)*[(d)] | 4.57 | 158 % | 1.77 | (19)% | 2.18 |
| **Benchmarks** | | | | | |
| WTI crude oil average of daily prices *(per bbl)* | $ 68.11 | 73 % | $ 39.34 | (31)% | $ 57.04 |
| Magellan East Houston ("MEH") crude oil average of daily prices *(per bbl)* | 69.25 | 73 % | 39.95 | (36)% | 61.96 |
| Mont Belvieu NGLs *(per bbl)*[(e)] | 29.17 | 99 % | 14.69 | (18)% | 17.81 |
| Henry Hub natural gas settlement date average *(per mmbtu)* | 3.84 | 85 % | 2.08 | (21)% | 2.63 |

(a) Excludes gains or losses on commodity derivative instruments.

(b) Inclusion of realized gains (losses) on crude oil derivative instruments would have decreased average price realizations by \$4.76 per bbl for 2021 and increased average price realizations by \$2.14 per bbl and \$0.67 per bbl for 2020 and 2019, respectively.

(c) Inclusion of realized gains (losses) on NGL derivative instruments would have decreased average price realizations by \$1.86 per bbl for 2021 and would have had a minimal impact on average price realizations for 2020. We did not have any NGL derivative instruments during 2019.

(d) Inclusion of realized gains (losses) on natural gas derivative instruments would have decreased average price realizations by \$0.56 per mcf for 2021 and would have had a minimal impact on average price realizations for the other periods presented.

(e) Bloomberg Finance LLP: Y-grade Mix NGL of 55% ethane, 25% propane, 5% butane, 8% isobutane and 7% natural gasoline.

*Crude oil and condensate* – Price realizations may differ from benchmarks due to the quality and location of the product.

*Natural gas liquids* – The majority of our sales volumes are at reference to Mont Belvieu prices.

*Natural gas* – A significant portion of volumes are sold at bid-week prices, or first-of-month indices relative to our producing areas.

***International***

The following table presents our average price realizations and the related benchmark for crude oil for 2021, 2020 and 2019.

| | 2021 | Increase (Decrease) | 2020 | Increase (Decrease) | 2019 |
|---|---|---|---|---|---|
| **Average Price Realizations** | | | | | |
| Crude oil and condensate *(per bbl)* | $ 57.46 | 103 % | $ 28.36 | (47)% | $ 53.09 |
| Natural gas liquids *(per bbl)* | 1.00 | — % | 1.00 | (29)% | 1.40 |
| Natural gas *(per mcf)* | 0.24 | — % | 0.24 | (27)% | 0.33 |
| **Benchmark** | | | | | |
| Brent (Europe) crude oil *(per bbl)*[(a)] | $ 70.68 | 69 % | $ 41.76 | (35)% | $ 64.36 |

(a) Average of monthly prices obtained from the United States Energy Information Agency website.

<u>United Kingdom</u>

*Crude oil and condensate* – Generally sold in relation to the Brent crude benchmark. We closed on the sale of our U.K. business on July 1, 2019.

*Equatorial Guinea*

*Crude oil and condensate* – Alba field liquids production is primarily condensate. MEGPL and Marathon E.G. International Limited generally sell their share of condensate in relation to the Brent crude benchmark. Alba Plant LLC processes the rich hydrocarbon gas which is supplied from the Alba field under a fixed-price long term contract. Alba Plant LLC extracts NGLs and secondary condensate which is then sold by Alba Plant LLC at market prices, with our share of the revenue reflected in income from equity method investments on the consolidated statements of income. Alba Plant LLC delivers the processed dry natural gas to the Alba Unit Parties for distribution and sale to AMPCO and EG LNG.

*Natural gas liquids* – Wet gas is sold to Alba Plant LLC at a fixed-price long term contract resulting in realized prices not tracking market price. Alba Plant LLC extracts and keeps NGLs, which are sold at market price, with our share of income from Alba Plant LLC being reflected in the income from equity method investments on the consolidated statements of income.

*Natural gas* – Dry natural gas, processed by Alba Plant LLC on behalf of the Alba Unit Parties, is sold by the Alba Unit to EG LNG and AMPCO at fixed-price long term contracts resulting in realized prices not tracking market price. We derive additional value from the equity investment in our downstream gas processing units EG LNG and AMPCO. EG LNG sells LNG on a market-based long term contract and AMPCO markets methanol at market prices. Alba Plant LLC and EG LNG process third party gas under a combination of a tolling and a market linked profit-sharing arrangement, the benefits of which are included in our respective share of income from equity method investees.

## Consolidated Results of Operations: 2021 compared to 2020

*Revenues from contracts with customers* are presented by segment in the table below:

| | Year Ended December 31, | |
|---|---|---|
| *(In millions)* | **2021** | **2020** |
| **Revenues from contracts with customers** | | |
| United States | $ 5,334 | $ 2,924 |
| International | 267 | 173 |
| Segment revenues from contracts with customers | $ 5,601 | $ 3,097 |

Below is a price/volume analysis for each segment. Refer to the preceding **Operations** and **Market Conditions** sections for additional detail related to our net sales volumes and average price realizations.

| | | Increase (Decrease) Related to | | |
|---|---|---|---|---|
| *(In millions)* | **Year Ended December 31, 2020** | **Price Realizations** | **Net Sales Volumes** | **Year Ended December 31, 2021** |
| **United States Price/Volume Analysis** | | | | |
| Crude oil and condensate | $ 2,322 | $ 1,817 | $ (214) | $ 3,925 |
| Natural gas liquids | 243 | 397 | 13 | 653 |
| Natural gas | 275 | 386 | (29) | 632 |
| Other sales | 84 | | | 124 |
| Total | $ 2,924 | | | $ 5,334 |
| **International Price/Volume Analysis** | | | | |
| Crude oil and condensate | $ 140 | $ 122 | $ (22) | $ 240 |
| Natural gas liquids | 4 | — | (2) | 2 |
| Natural gas | 29 | — | (6) | 23 |
| Other sales | — | | | 2 |
| Total | $ 173 | | | $ 267 |

*Net gain (loss) on commodity derivatives* in 2021 was a net loss of $383 million, compared to a net gain of $116 million in 2020. We have multiple crude oil, NGL and natural gas derivative contracts that settle against various indices. We record commodity derivative gains/losses as the index pricing and forward curves change each period. See **Note 16** to the consolidated financial statements for further information.

*Income (loss) from equity method investments* increased $414 million in 2021 from 2020. Our investees benefited from higher price realizations in 2021. Also, we recognized impairments of $171 million related to an investment in an equity method investee in 2020; there were no such impairments in 2021.

*Net gain (loss) on disposal of assets* in 2021 was a net loss of $19 million, compared to a net gain of $9 million in 2020. In 2021, we recognized a $20 million pre-tax loss related to a previously divested non-core conventional asset and a $12 million pre-tax loss associated with a reduction in our ownership interest in one of our equity method investees. See **Note 24** to the consolidated financial statements for further detail regarding the reduction in ownership.

*Production expenses* decreased $21 million during 2021 from 2020, primarily as a result of the U.S. segment's continued cost management, specifically staffing and contract labor. This was partially offset by timing of project activity. Our U.S. and International segments production expense rates increased due to lower sales volumes.

The following table provides production expense and production expense rates for each segment:

| *(In millions; rate in $ per boe)* | 2021 | 2020 | Increase (Decrease) | 2021 | 2020 | Increase (Decrease) |
|---|---|---|---|---|---|---|
| **Production Expense and Rate** | **Expense** | | | **Rate** | | |
| United States | $ 480 | $ 494 | (3)% | $ 4.60 | $ 4.42 | 4 % |
| International | $ 54 | $ 59 | (8)% | $ 2.45 | $ 2.12 | 16 % |

*Shipping, handling and other operating expenses* increased $131 million in 2021 from 2020. Certain of our processing arrangements with midstream entities are percentage-of-proceeds contracts. We classify the proceeds retained by the midstream companies as shipping and handling costs. The increase in shipping and handling costs of these percentage-of-proceeds contracts coincides with the increase in realized natural gas liquids prices. In addition, higher marketing costs contributed to the increase as we purchased additional volumes for resale to satisfy transportation commitments. This was partially offset by lower legal expenses in 2021.

*Exploration expenses* include unproved property impairments, dry well costs, geological and geophysical and other costs. The decrease in unproved property impairments was primarily driven by a $78 million impairment of unproved property leases in Louisiana Austin Chalk in our U.S. segment in 2020 due to a combination of factors, including our geological assessment, seismic information, timing of lease expiration dates and decisions not to develop acreage deemed non-core. See **Note 12** to the consolidated financial statements for discussion on the impairment in further detail. We also incurred approximately $20 million less expense related to amortization of insignificant unproved property lease balances in 2021. Finally, dry well costs for 2021 include an impairment of suspended costs associated with drilled and uncompleted wells, primarily in the Permian, due to a change in our plan of development.

The following table summarizes the components of exploration expenses:

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | 2021 | 2020 | Increase (Decrease) |
| **Exploration Expenses** | | | |
| Unproved property impairments | $ 92 | $ 157 | (41)% |
| Dry well costs | 33 | 2 | 1,550 % |
| Geological and geophysical | 5 | 6 | (17)% |
| Other | 6 | 16 | (63)% |
| Total exploration expenses | $ 136 | $ 181 | (25)% |

*Depreciation, depletion and amortization* decreased $250 million in 2021 from 2020, primarily as a result of lower sales volumes in our U.S. and International segments. Our segments apply the units-of-production method to majority of their assets, including capitalized asset retirement costs; therefore volumes have an impact on DD&A expense.

The DD&A rate (expense per boe) is affected by field-level changes in reserves, capitalized costs and sales volume mix between fields. The following table provides DD&A expense and DD&A expense rates for each segment:

| (In millions; rate in $ per boe) | 2021 | 2020 | Increase (Decrease) | 2021 | 2020 | Increase (Decrease) |
|---|---|---|---|---|---|---|
| **DD&A Expense and Rate** | | **Expense** | | | **Rate** | |
| United States | $ 1,972 | $ 2,211 | (11)% | $ 18.90 | $ 19.76 | (4)% |
| International | $ 68 | $ 82 | (17)% | $ 3.07 | $ 2.89 | 6 % |

*Impairments* decreased $84 million in 2021 from 2020. Impairments in 2021 included $30 million related to an increase in the estimated future decommissioning costs of certain non-producing wells, pipelines and production facilities for previously divested offshore assets located in the Gulf of Mexico and $24 million related to certain decommissioned Eagle Ford central facilities.

In 2020, impairments consisted of a $95 million goodwill charge related to our International reporting unit and a $49 million long-lived asset impairment related to a damaged, unsalvageable well and related equipment in the Louisiana Austin Chalk. See **Note 12**, **Note 13**, and **Note 26** to the consolidated financial statements for discussions of these impairments in further detail.

*Taxes other than income* include production, severance and ad valorem taxes, primarily in the U.S., which tend to increase or decrease in relation to revenue and sales volumes. Taxes other than income increased by $145 million in 2021 from 2020 period primarily due to higher price realizations in the U.S. segment in 2021.

*Net interest and other* decreased $68 million in 2021 versus 2020, primarily as a result of gains on our forward interest rates swaps. We recognized $54 million of cumulative gains within Net interest and other during 2021 related to our interest rate swaps as compared to $12 million of gains in 2020. Additionally, our interest expense decreased as a result of our early extinguishment of debt in 2021. See **Note 16** to the consolidated financial statements for further discussion of the interest rate swaps.

*General and administrative expenses* increased $17 million in 2021 compared to 2020, primarily as a result of a $13 million expense associated with the termination of an aircraft lease agreement during the first quarter of 2021.

*Loss on early extinguishment of debt* was $121 million for 2021, as compared to $28 million for 2020. The loss in 2021 was incurred upon redemption of our $500 million 2.8% Senior Notes due 2022 and $900 million 3.85% Senior Notes due 2025 in the second and third quarters of 2021, respectively. See **Note 18** to the consolidated financial statements for further detail.

*Provision (benefit) for income taxes* reflects an effective income tax rate of 6% for 2021, as compared to an effective income tax rate of 1% for 2020. See **Note 8** to the consolidated financial statements for a discussion of the effective income tax rate.

## Segment Results: 2021 compared to 2020

### *Segment Income*

Segment income represents income which excludes certain items not allocated to our operating segments, net of income taxes. A portion of our corporate and operations general and administrative support costs are not allocated to the operating segments. These unallocated costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate and operations support activities. Additionally, items which affect comparability such as: gains or losses on dispositions, impairments of proved and certain unproved properties, goodwill and equity method investments, unrealized gains or losses on commodity derivative instruments, gains or losses on interest rate derivative instruments, effects of pension settlements and curtailments, or other items (as determined by the chief operating decision maker (CODM)) are not allocated to operating segments.

The following table reconciles segment income (loss) to net income (loss):

| | Year Ended December 31, | |
|---|---|---|
| *(In millions)* | **2021** | **2020** |
| United States | $ 1,277 | $ (553) |
| International | 317 | 30 |
| Segment income (loss) | 1,594 | (523) |
| Items not allocated to segments, net of income taxes[a] | (648) | (928) |
| Net income (loss) | $ 946 | $ (1,451) |

[a] See Item 8. Financial Statements and Supplementary Data – **Note 7** to the consolidated financial statements for further detail about items not allocated to segments.

*United States segment income (loss)* in 2021 was $1.3 billion of income versus a $553 million loss in 2020. This increase was primarily due to higher price realizations and lower DD&A expenses. These favorable changes were partially offset by lower sales volumes, realized losses on commodity derivatives (as compared to realized gains in the prior period), higher shipping and handling costs and higher production taxes in 2021.

*International segment income (loss)* in 2021 was $317 million of income versus $30 million of income in 2020, primarily due to higher price realizations in E.G. in 2021 in our consolidated operations and our equity method investees.

## Consolidated Results of Operations: 2020 compared to 2019

A detailed discussion of the year-over-year changes from the year ended December 31, 2020 to December 31, 2019 can be found in the Management's Discussion and Analysis section of our Annual Report on Form 10-K for the year ended December 31, 2020 and is available via the SEC's website at www.sec.gov and on our website at www.marathonoil.com.

## Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity

Commodity prices are the most significant factor impacting our revenues, profitability, operating cash flows, the amount of capital we invest in our business, principal debt repayments, payment of dividends and funding of share repurchases. As commodity prices increased during 2021, we generated positive cash flow from operations. We continue to expect volatility in commodity prices and that could impact how much cash flow from operations we generate.

As previously discussed in the Outlook section, our capital budget for 2022 is $1.2 billion. Our top priorities for using cash provided by operations are to fund our capital budget, dividends and share repurchases, while also enhancing liquidity. We believe our current liquidity level, cash flow from operations and ability to access the capital markets provides us with the flexibility to fund our business across a wide range of commodity price environments.

### *Cash Flows*

The following table presents sources and uses of cash and cash equivalents for 2021 and 2020:

| (In millions) | Year Ended December 31, 2021 | 2020 |
|---|---|---|
| **Sources of cash and cash equivalents** | | |
| Operating activities | $ 3,239 | $ 1,473 |
| Borrowings | — | 400 |
| Disposal of assets, net of cash transferred to the buyer | 22 | 18 |
| Equity method investments - return of capital | 61 | 7 |
| Other | 1 | 1 |
| Total sources of cash and cash equivalents | $ 3,323 | $ 1,899 |
| **Uses of cash and cash equivalents** | | |
| Additions to property, plant and equipment | $ (1,046) | $ (1,343) |
| Additions to other assets | — | 15 |
| Acquisitions, net of cash acquired | (47) | (1) |
| Purchases of common stock | (734) | (92) |
| Debt repayments | (1,400) | (500) |
| Debt extinguishment costs | (117) | (27) |
| Dividends paid | (141) | (64) |
| Other | — | (3) |
| Total uses of cash and cash equivalents | $ (3,485) | $ (2,015) |

Cash flows generated from operating activities in 2021 were 120% higher compared to 2020, primarily as a result of higher realized commodity prices. These were partially offset by net realized losses on commodity derivatives (compared to realized gains in prior period) and the impact from lower production volumes.

The following table shows capital expenditures by segment and reconciles to additions to property, plant and equipment as presented in the consolidated statements of cash flows:

| (In millions) | Year Ended December 31, 2021 | 2020 |
|---|---|---|
| United States | $ 1,018 | $ 1,137 |
| International | — | 1 |
| Corporate | 14 | 13 |
| Total capital expenditures | 1,032 | 1,151 |
| Change in capital expenditure accrual | 14 | 192 |
| Total use of cash and cash equivalents for property, plant and equipment | $ 1,046 | $ 1,343 |

The decline in our capital expenditures for the U.S. segment in 2021 compared to 2020 was caused by lower drilling and completions activities across all four of our resource plays.

## Liquidity and Capital Resources

### *Capital Resources and Available Liquidity*

Our main sources of liquidity are cash and cash equivalents, internally generated cash flow from operations, sales of non-core assets, capital market transactions and our revolving Credit Facility. At December 31, 2021, we had approximately $3.7 billion of liquidity consisting of $580 million in cash and cash equivalents and $3.1 billion available under our revolving Credit Facility.

Our working capital requirements are supported by our cash and cash equivalents and our Credit Facility. We may draw on our revolving Credit Facility to meet short-term cash requirements or issue debt or equity securities through the shelf registration statement discussed below as part of our longer-term liquidity and capital management program. Because of the alternatives available to us as discussed above, we believe that our short-term and long-term liquidity are adequate to fund not only our current operations, but also our near-term and long-term funding requirements including our capital spending programs, defined benefit plan contributions, repayment of debt maturities, dividends and other amounts that may ultimately be paid in connection with contingencies. See Item 8. Financial Statements and Supplementary Data – **Note 26** to the consolidated financial statements for a further discussion of how our commitments and contingencies could affect our available liquidity. General economic conditions, commodity prices and financial, business and other factors, including the global pandemic, could affect our operations and our ability to access the capital markets.

We continue to be rated investment grade at all three primary credit rating agencies. A downgrade in our credit ratings could increase our future cost of financing or limit our ability to access capital and could result in additional credit support requirements. We do not have any triggers on any of our corporate debt that would cause an event of default in the case of a downgrade of our credit ratings. See **Item 1A. Risk Factors** for a discussion of how a downgrade in our credit ratings could affect us.

We may incur additional debt in order to fund our capital expenditures, acquisitions or development activities or for general corporate or other purposes. A higher level of indebtedness could increase the risk that our liquidity and financial flexibility deteriorates. See **Item 1A. Risk Factors** for a further discussion of how our level of indebtedness could affect us.

*Credit Arrangements and Borrowings*

In June 2021, we executed the sixth amendment to our unsecured Credit Facility. The primary changes resulting from this amendment are (i) increasing the size of the Credit Facility from $3.0 billion to $3.1 billion (ii) extending the maturity of the commitments of certain consenting lenders from May 28, 2023 to June 21, 2024 (with the remaining commitment of a single non-consenting lender to mature on May 28, 2023, at which time the size of the Credit Facility will be reduced back down to $3.0 billion) and (iii) including certain other provisions and revisions, including provisions provide for the eventual replacement of LIBOR as a benchmark interest rate. The Credit Facility includes a single financial covenant requiring that our ratio of total debt to total capitalization (debt-to-capital ratio) not exceed 65% as of the last day of each fiscal quarter. Our total debt-to-capital ratio was 20% at December 31, 2021. See Item 8. Financial Statements and Supplementary Data – **Note 18** to the consolidated financial statements for further information.

As of December 31, 2021, we had no borrowings on our $3.1 billion Credit Facility and $4.0 billion of total long-term debt outstanding.

*Shelf Registration*

We have a universal shelf registration statement filed with the SEC under which we, as a “well-known seasoned issuer” for purposes of SEC rules, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

### *Capital Requirements*

Our material cash requirements include the following contractual and other obligations:

*Capital Spending*

See the Cash Flows section above for discussion around our 2021 capital expenditures. Our approved capital budget for 2022 is $1.2 billion. Additional details were previously discussed in **Outlook**.

*Debt*

In April 2021, we fully redeemed our outstanding $500 million 2.8% Senior Notes due 2022 and the redemption will reduce annual cash interest expense by $14 million. As a result of the redemption, we incurred $19 million in costs related to a make-whole provision premium and the write off of unamortized discount and issuance costs in the second quarter of 2021. In September 2021, we fully redeemed our outstanding $900 million 3.85% Senior Notes due 2025 and the redemption will reduce annual cash interest expense by approximately $35 million. As a result of the redemption, we incurred $102 million in costs related to the make-whole provision premium and the write off of unamortized discount and issuance costs in the third quarter of 2021. Our next significant long-term debt maturity is in the amount of $1.0 billion due 2027.

See Item 8. Financial Statements and Supplementary Data – **Note 18** to the consolidated financial statements for details regarding future debt maturities. Anticipated cash payments for interest in future periods are $197 million for 2022, $364 million for 2023-2024, $331 million for 2025-2026 and $1.3 billion for the remaining years for a total of $2.2 billion.

*Share Repurchase Program*

In the fourth quarter of 2021, we resumed our share repurchase program and repurchased $724 million of shares of our common stock. Effective November 3, 2021, our Board of Directors increased our remaining share repurchase program authorization from $1.1 billion to $2.5 billion. As of December 31, 2021, $1.9 billion of share repurchase program authorization remains. Additionally, we repurchased $10 million of shares during 2021 related to our tax withholding obligation associated with the vesting of employee restricted stock awards.

Subsequent to December 31, 2021, we repurchased approximately $258 million of shares of our common stock through February 16, 2022.

*Leases*

In 2018, we signed an agreement with an owner/lessor to construct and lease a new build-to-suit office building in Houston, Texas. Construction was completed and the lease commenced in September 2021. See Item 8. Financial Statements and Supplementary Data – **Note 14** to the consolidated financial statements for further information related to the building lease.

For future lease obligations, see Item 8. Financial Statements and Supplementary Data – **Note 14** to the consolidated financial statements.

*Dividends*

During 2021, we paid dividends totaling $141 million. On January 26, 2022, our Board of Directors approved a dividend of $0.07 per share for the fourth quarter of 2021. The dividend is payable on March 10, 2022 to shareholders of record on February 16, 2022.

*Pension and Postretirement Plans*

Estimated cash payments for our pension and other postretirement benefits plans in future periods are $39 million for 2022, $68 million for 2023-2024, $57 million for 2025-2026 and $178 million for the remaining years for a total of $342 million.

*Other Cash Obligations*

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2021.

| *(In millions)* | Total | 2022 | 2023-2024 | 2025-2026 | Later Years |
|---|---|---|---|---|---|
| Purchase obligations: | | | | | |
| Oil and gas activities | $ 16 | $ 7 | $ 1 | $ 2 | $ 6 |
| Service and materials contracts[(a)] | 79 | 63 | 16 | — | — |
| Transportation and marketing commitments[(b)] | 1,503 | 234 | 448 | 407 | 414 |
| Other | 12 | 11 | 1 | — | — |
| Total purchase obligations | 1,610 | 315 | 466 | 409 | 420 |
| Other long-term liabilities reported in the consolidated balance sheet | 10 | — | 8 | — | 2 |
| Total other contractual cash obligations[(c)] | $ 1,620 | $ 315 | $ 474 | $ 409 | $ 422 |

(a) Includes contracts to purchase services such as utilities, supplies and various other maintenance and operating services.

(b) These obligations consist of firm capacity on third-party pipelines, minimum volume throughput and firm purchase commitments.

(c) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $316 million. See Item 8. Financial Statements and Supplementary Data – **Note 13** to the consolidated financial statements.

## Transactions with Related Parties

Offshore E.G., we own a 64% working interest in the Alba Unit. Onshore E.G., we own a 52% interest in an LPG processing plant, a 56% interest in an LNG production facility and a 45% interest in a methanol production plant, each through equity method investees. We sell our natural gas from the Alba Unit to these equity method investees as the feedstock for their production processes.

## Off-Balance Sheet Arrangements

Off-balance sheet arrangements comprise those arrangements that may potentially impact our liquidity, capital resources and results of operations, even though such arrangements are not recorded as liabilities under accounting principles generally accepted in the U.S. We had no material off-balance sheet arrangements for December 31, 2021, 2020 and 2019.

## Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies

We have incurred and will continue to incur capital, operating and maintenance and remediation expenditures as a result of environmental laws and regulations. If these expenditures, as with all costs, are not ultimately offset by the prices of our products and services, our operating results will be adversely affected. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas and production processes. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance.

We accrue for environmental remediation activities when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. As environmental remediation matters proceed toward ultimate resolution or as additional remediation obligations arise, charges in excess of those previously accrued may be required.

New or expanded environmental requirements, which could increase our environmental costs, may arise in the future on both state and federal levels. We strive to comply with all legal requirements regarding the environment, but as not all costs are fixed or presently determinable (even under existing legislation) and may be affected by future legislation or regulations, it is not possible to predict all of the ultimate costs of compliance, including remediation costs that may be incurred and penalties that may be imposed.

For more information on environmental regulations, litigation and contingencies that impact us, or could impact us, see **Item 1. Business – Environmental, Health and Safety Matters**, **Item 1A. Risk Factors**, **Item 3. Legal Proceedings** and **Item 8. Financial Statements and Supplementary Data — Note 26**.

## Critical Accounting Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the U.S. requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change, and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

### *Estimated Quantities of Net Reserves*

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved crude oil and condensate, NGLs and natural gas reserves. The amount of estimated proved reserve volumes affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depreciated, depleted or amortized into net income and the presentation of supplemental information on oil and gas producing activities. In addition, the expected future cash flows to be generated by producing properties are used for testing impairment and the expected future taxable income available to realize deferred tax assets, also in part, rely on estimates of quantities of net reserves. Refer to the applicable sections below for further discussion of these accounting estimates.

The estimation of quantities of net reserves is a highly technical process performed by our petroleum engineers and geoscientists for crude oil and condensate, NGLs and natural gas, which is based upon several underlying assumptions. The reserve estimates may change as additional information becomes available and as contractual, operational, economic and political conditions change. We evaluate our reserves using drilling results, reservoir performance, subsurface interpretation and future plans to develop acreage. Technologies used in proved reserves estimation includes statistical analysis of production performance, decline curve analysis, pressure and rate transient analysis, pressure gradient analysis, reservoir simulation and volumetric analysis. The observed statistical nature of production performance coupled with highly certain reservoir continuity or quality and sufficient proved developed locations establish the reasonable certainty criteria required for booking proved reserves. As per SEC requirements, proved undeveloped reserve volumes are limited to activity in the 5-year plan and wells that will be developed within 5 years of initial booking. The data for a given reservoir may also change over time as a result of numerous factors including, but not limited to, additional development activity and future development costs, production history and continual reassessment of the viability of future production volumes under varying economic conditions.

Reserve estimates are based on an unweighted average of commodity prices in the prior 12-month period using the closing prices on the first day of each month, as defined by the SEC. The table below provides the 2021 SEC pricing for certain benchmark prices:

| | | **2021 SEC Pricing** |
|---|---|---|
| WTI crude oil *(per bbl)* | $ | 66.56 |
| Henry Hub natural gas *(per mmbtu)* | $ | 3.60 |
| Brent crude oil *(per bbl)* | $ | 69.47 |
| Mont Belvieu NGLs *(per bbl)* | $ | 28.57 |

When determining the December 31, 2021 proved reserves for each property, the benchmark prices listed above were adjusted using price differentials that account for property-specific quality and location differences.

If the future average crude oil prices are below the average prices used to determine proved reserves at December 31, 2021, it could have an adverse effect on our estimates of proved reserve volumes and the value of our business. Future reserve revisions could also result from changes in capital funding, drilling plans and governmental regulation, among other things. It is difficult to estimate the magnitude of any potential price change and the effect on proved reserves, due to numerous factors (including future crude oil price and performance revisions). For further discussion of risks associated with our estimation of proved reserves, see Part I. **Item 1A. Risk Factors**.

Depreciation and depletion of crude oil and condensate, NGLs and natural gas producing properties is determined by the units-of-production method and could change with revisions to estimated proved reserves. While revisions of previous reserve estimates have not historically been significant to the depreciation and depletion rates of our segments, any reduction in proved reserves, could result in an acceleration of future DD&A expense. The following table illustrates, on average, the sensitivity of each segment's units-of-production DD&A per boe and pretax income to a hypothetical 10% change in 2021 proved reserves based on 2021 production.

| (In millions, except per boe) | Impact of a 10% Increase in Proved Reserves | | Impact of a 10% Decrease in Proved Reserves | |
|---|---|---|---|---|
| | DD&A per boe | Pretax Income | DD&A per boe | Pretax Income |
| United States | $ (1.72) | $ 179 | $ 2.10 | $ (219) |
| International | $ (0.28) | $ 6 | $ 0.34 | $ (8) |

***Fair Value Estimates***

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value, or range of present values, using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and do not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

- Level 1 – Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the measurement date.
- Level 3 – Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. See Item 8. Financial Statements and Supplementary Data – **Note 17** to the consolidated financial statements for disclosures regarding our fair value measurements.

Significant uses of fair value measurements include:

- assets and liabilities acquired in a business combination;
- assets acquired in an asset acquisition;
- impairment assessments of long-lived assets;
- impairment assessments of equity method investments;
- impairment assessments of goodwill;
- recorded value of derivative instruments; and
- recorded value of pension plan assets.

The need to test long-lived assets and goodwill for impairment can be based on several indicators, including a significant reduction in prices of crude oil and condensate, NGLs and natural gas, sustained declines in our common stock, reductions to our capital budget, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment in which the property is located.

*Impairment Assessments of Long-Lived Assets*

Long-lived assets in use are assessed for impairment whenever changes in facts and circumstances indicate that the carrying value of the assets may not be recoverable. For purposes of an impairment evaluation, long-lived assets must be grouped at the lowest level for which independent cash flows can be identified, which generally is field-by-field or, in certain instances, by logical grouping of assets if there is significant shared infrastructure or contractual terms that cause economic interdependency amongst separate, discrete fields. If the sum of the undiscounted estimated cash flows from the use of the asset group and its eventual disposition is less than the carrying value of an asset group, the carrying value is written down to the estimated fair value.

Fair value calculated for the purpose of testing our long-lived assets for impairment is estimated using the present value of expected future cash flows method and comparative market prices when appropriate. Significant judgment is involved in performing these fair value estimates since the results are based on forecasted assumptions. Significant assumptions include:

- *Future crude oil and condensate, NGLs and natural gas prices.* Our estimates of future prices are based on our analysis of market supply and demand and consideration of market price indicators. Although these commodity prices may experience extreme volatility in any given year, we believe long-term industry prices are driven by global market supply and demand. To estimate supply, we consider numerous factors, including the worldwide resource base, depletion rates and OPEC production policies. We believe demand is largely driven by global economic factors, such as population and income growth, governmental policies and vehicle stocks. The prices we use in our fair value estimates are consistent with those used in our planning and capital investment reviews. There has been significant volatility in crude oil and condensate, NGLs and natural gas prices and estimates of such future prices are inherently imprecise. See Item 1A. Risk Factors for further discussion on commodity prices.
- *Estimated quantities of crude oil and condensate, NGLs and natural gas.* Such quantities are based on a combination of proved reserves and risk-weighted probable reserves and resources such that the combined volumes represent the most likely expectation of recovery. See Part I. Item 1A. Risk Factors for further discussion on reserves.
- *Expected timing of production.* Production forecasts are the outcome of engineering studies which estimate reserves, as well as expected capital programs. The actual timing of the production could be different than the projection. Cash flows realized later in the projection period are less valuable than those realized earlier due to the time value of money. The expected timing of production that we use in our fair value estimates is consistent with that used in our planning and capital investment reviews.
- *Discount rate commensurate with the risks involved.* We apply a discount rate to our expected cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. A higher discount rate decreases the net present value of cash flows.
- *Future capital requirements.* Our estimates of future capital requirements are based upon a combination of authorized spending and internal forecasts.

We base our fair value estimates on projected financial information which we believe to be reasonably likely to occur. An estimate of the sensitivity to changes in assumptions in our undiscounted cash flow calculations is not practicable, given the numerous assumptions (e.g. reserves, pace and timing of development plans, commodity prices, capital expenditures, operating costs, drilling and development costs, inflation and discount rates) that can materially affect our estimates. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced commodity prices on future undiscounted cash flows would likely be partially offset by lower costs. As of December 31, 2021 our estimated undiscounted cash flows relating to our remaining long-lived assets significantly exceeded their carrying values.

During 2021, we recorded impairment charges totaling $131 million related to proved and certain unproved properties. See Item 8. Financial Statements and Supplementary Data – **Note 7**, **Note 12** and **Note 17** to the consolidated financial statements for discussion of impairments recorded in 2021, 2020 and 2019 and the related fair value measurements.

*Impairment Assessment of Equity Method Investments*

Equity method investments are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value may have occurred. When a loss is deemed to have occurred that is other than temporary, the carrying value of the equity method investment is written down to fair value.

Fair value calculated for the purpose of testing our equity method investees for impairment is estimated using the present value of expected future cash flows method. Significant judgment is involved in performing these fair value estimates since the results are based on forecasted assumptions and the performance of entities that we do not control. Significant assumptions include:

- Future condensate, NGL, LNG, natural gas and methanol prices. Our estimates of future prices are based on our analysis of market supply and demand and consideration of market price indicators. Although these commodity prices may experience extreme volatility in any given year, we believe long-term industry prices are driven by global market supply and demand. To estimate supply, we consider numerous factors, including the worldwide resource base, depletion rates and OPEC production policies. We believe demand is largely driven by global economic factors, such as population and income growth, and governmental policies. The prices we use in our fair value estimates are consistent with those used in our planning and capital investment reviews. There has been significant volatility in commodity prices and estimates of such future prices are inherently imprecise.

- Estimated quantities of feedstock condensate, NGLs and natural gas processed by our investees. There are two primary sets of inputs used to estimate feedstock volumes processed by our investees. The first input involves hydrocarbons produced from our Alba Field. Our equity method investees currently process hydrocarbons from our Alba Field, which consists of condensate, NGLs and natural gas reserves. Estimated quantities of hydrocarbons processed from our Alba Field are based on a combination of proved reserves and risk-weighted probable reserves and resources such that the combined volumes represent the most likely expectation of recovery.

  The second input involves our estimate of future third-party gas to be processed by our investees. Our investees have capacity to process hydrocarbons from sources other than our Alba field. During 2019, we executed agreements for processing natural gas produced from the third party-owned Alen Unit through the existing Alba Plant LLC LPG processing plant and the EGHoldings LNG production facility beginning in 2021. Estimated natural gas volumes processed from the Alen Unit were based on forecasts received from the operator of the Alen Unit.

- Expected timing of production. Production forecasts are the outcome of engineering studies which estimate reserves, as well as expected capital programs. The actual timing of the production could be different than the projection. Cash flows realized later in the projection period are less valuable than those realized earlier due to the time value of money. The expected timing of production from the Alba Field that we use in our fair value estimates is consistent with that used in our planning and capital investment reviews. The expected timing of production from the Alen Unit is consistent with forecasts received from the operator of that field.
- Discount rate commensurate with the risks involved. We apply a discount rate to our expected cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. A higher discount rate decreases the net present value of cash flows.

We base our fair value estimates on projected financial information which we believe to be reasonably likely to occur. This includes the estimated dividends and/or return of capital we expect to be paid by our equity method investees, which are directly affected by the significant assumptions described in the preceding paragraphs. An estimate of the sensitivity to changes in assumptions in our cash flow calculations is not practicable, given the numerous other assumptions (e.g. reserves, commodity prices, operating costs, inflation and discount rates) that can materially affect our estimates. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions.

During 2021, we had no impairments related to our equity method investments. See Item 8. Financial Statements and Supplementary Data – **Note 12** to the consolidated financial statements for further information regarding the impairment recognized during 2020.

*Impairment Assessments of Goodwill*

Goodwill is tested for impairment on an annual basis, or between annual tests when events or changes in circumstances indicate the fair value may have been reduced below its carrying value. Goodwill is tested for impairment at the reporting unit level. Our reporting units are the same as our reporting segments, of which historically only International included goodwill. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. Our policy is to first assess the qualitative factors in order to determine whether the fair value of our International reporting unit is more likely than not less than its carrying amount. Certain qualitative factors used in our evaluation include, among other things, the results of the most recent quantitative assessment of the goodwill impairment test; macroeconomic conditions; industry and market conditions (including commodity prices and cost factors); overall financial performance; and other relevant entity-specific events. If, after considering these events and circumstances we determined that it is more likely than not that the fair value of the International reporting unit is less than its carrying amount, a quantitative goodwill test is performed. The quantitative goodwill test is performed using a combination of market and income approaches. The market approach references observable inputs specific to us and our industry, such as the price of our common equity, our enterprise value and valuation multiples of us and our peers from the investor analyst community. The income approach utilizes discounted cash flows, which are based on forecasted assumptions. Key assumptions to the income approach are the same as those described above regarding our impairment assessment of long-lived assets and are consistent with those that management uses to make business decisions.

See Item 8. Financial Statements and Supplementary Data – **Note 15** to the consolidated financial statements for information regarding the $95 million full impairment of our goodwill in 2020.

*Derivatives*

We record all derivative instruments at fair value. Fair value measurements for all our derivative instruments are based on observable market-based inputs that are corroborated by market data and are discussed in Item 8. Financial Statements and

Supplementary Data – **Note 16** to the consolidated financial statements. Additional information about derivatives and their valuation may be found in **Item 7A. Quantitative and Qualitative Disclosures About Market Risk**.

*Pension Plan Assets*

Pension plan assets are measured at fair value. See Item 8. Financial Statements and Supplementary Data – **Note 20** to the consolidated financial statements for discussion of the fair value of plan assets and the presentation of the fair value of our defined benefit pension plan's assets by level within the fair value hierarchy as of December 31, 2021 and 2020.

***Income Taxes***

We are subject to income taxes in numerous taxing jurisdictions worldwide. Estimates of income taxes to be recorded involve interpretation of complex tax laws and assessment of the effects of foreign taxes on our U.S. federal income taxes.

Uncertainty exists regarding tax positions taken in previously filed tax returns which remain subject to examination, along with positions expected to be taken in future returns. We provide for unrecognized tax benefits, based on the technical merits, when it is more likely than not that an uncertain tax position will not be sustained upon examination. Adjustments are made to the uncertain tax positions when facts and circumstances change, such as the closing of a tax audit; court proceedings; changes in applicable tax laws, including tax case rulings and legislative guidance; or expiration of the applicable statute of limitations.

We have recorded deferred tax assets and liabilities, measured at enacted tax rates, for temporary differences between book basis and tax basis, tax credit carryforwards and operating loss carryforwards. In accordance with U.S. GAAP accounting standards, we routinely assess the realizability of our deferred tax assets 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 additional or adjustments to existing valuation allowances, we consider all available positive and negative evidence. Positive evidence includes reversals of temporary differences, forecasts of future taxable income, assessment of future business assumptions and applicable tax planning strategies that are prudent and feasible. Negative evidence includes losses in recent years as well as the forecasts of future loss in the realizable period. In making our assessment regarding valuation allowances, we weight the evidence based on objectivity.

We base our future taxable income estimates on projected financial information which we believe to be reasonably likely to occur. Numerous judgments and assumptions are inherent in the estimation of future taxable income, including factors such as future operating conditions and the assessment of the effects of foreign taxes on our U.S. federal income taxes. Future operating conditions can be affected by numerous factors, including (i) future crude oil and condensate, NGLs and natural gas prices, (ii) estimated quantities of crude oil and condensate, NGLs and natural gas, (iii) expected timing of production, and (iv) future capital requirements. These assumptions are described in further detail above regarding our impairment assessment of long-lived assets. An estimate of the sensitivity to changes in assumptions resulting in future taxable income calculations is not practicable, given the numerous assumptions that can materially affect our estimates. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced commodity prices on future taxable income would likely be partially offset by lower capital expenditures.

Based on the assumptions and judgments described above, as of December 31, 2021, we reflect a valuation allowance in our consolidated balance sheet of $780 million against our gross deferred tax assets of $2.3 billion in various jurisdictions in which we operate. Our gross deferred tax assets consist primarily of federal U.S. operating loss carryforwards of $295 million, which will expire in 2036 - 2037, and $1.1 billion which can be carried forward indefinitely. Since December 31, 2016, we have maintained a full valuation allowance on our net federal deferred tax assets. We intend to continue a full valuation allowance on these deferred tax assets until there is sufficient evidence to support the reversal of all or some portion of the allowance. However, if current commodity prices are sustained and absent any additional objective negative evidence, we expect it is reasonably possible that sufficient positive evidence will exist within the next 12 months to adjust our current valuation allowance position. Exact timing and amount of the adjustment to the valuation allowance is unknown at this time. See Item 8. Financial Statements and Supplementary Data – **Note 8** to the consolidated financial statements for further detail.

***Pension and Other Postretirement Benefit Obligations***

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the following:

- the discount rate for measuring the present value of future plan obligations;
- the expected long-term return on plan assets; and
- the rate of future increases in compensation levels.

We develop our estimate of demographic effects and utilize the work of third-party actuaries to assist in the measurement of these obligations. We have selected different discount rates for our U.S. pension plans and our other U.S. postretirement benefit plans due to the different projected benefit payment patterns. In determining the assumed discount rates, our methods include a review of market yields on high-quality corporate debt and use of our third-party actuary's discount rate model. This model calculates an equivalent single discount rate for the projected benefit plan cash flows using a yield curve derived from bond yields. The yield curve represents a series of annualized individual spot discount rates from 0.5 to 99 years. The bonds used are rated AA or higher by a recognized rating agency, only non-callable bonds are included and outlier bonds (bonds that have a yield to maturity that significantly deviates from the average yield within each maturity grouping) are removed. Each issue is required to have at least $300 million par value outstanding. The constructed yield curve is based on those bonds representing the 50% highest yielding issuances within each defined maturity group.

The asset rate of return assumption for the funded U.S. plan considers the plan's asset mix (currently targeted at approximately 55% equity and 45% other fixed income securities), past performance and other factors. Certain components of the asset mix are modeled with various assumptions regarding inflation, debt returns and stock yields.

Compensation change assumptions are based on historical experience, anticipated future management actions and demographics of the benefit plans.

Item 8. Financial Statements and Supplementary Data – **Note 20** to the consolidated financial statements includes detailed information about the assumptions used to calculate the components of our annual defined benefit pension and other postretirement plan expense, as well as the obligations and accumulated other comprehensive income reported on the consolidated balance sheets.

***Contingent Liabilities***

We accrue contingent liabilities for environmental remediation, tax deficiencies related to operating taxes, as well as tax disputes and litigation claims when such contingencies are probable and estimable. Actual costs can differ from estimates for many reasons. For instance, settlement costs for claims and litigation can vary from estimates based on differing interpretations of laws, opinions on responsibility and assessments of the amount of damages. Similarly, liabilities for environmental remediation may vary from estimates because of changes in laws, regulations and their interpretation, additional information on the extent and nature of site contamination and improvements in technology. Our in-house legal counsel regularly assesses these contingent liabilities. In certain circumstances outside legal counsel is utilized.

We generally record losses related to these types of contingencies as other operating expense or general and administrative expense in the consolidated statements of income, except for tax contingencies unrelated to income taxes, which are recorded as taxes other than income (such as production, severance and ad valorem taxes). For additional information on contingent liabilities, see **Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies**.

An estimate of the sensitivity to net income if other assumptions had been used in recording these liabilities is not practical because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, in terms of both the probability of loss and the estimates of such loss.

## Accounting Standards Not Yet Adopted

See Item 8. Financial Statements and Supplementary Data – **Note 2** to the consolidated financial statements.

## Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks in the normal course of business including commodity price risk and interest rate risk. We employ various strategies, including the use of financial derivatives to manage the risks related to commodity price fluctuations. See Item 8. Financial Statements and Supplementary Data – **Note 16** and **Note 17** to the consolidated financial statements for detail relating to our open commodity derivative positions, including underlying notional quantities, how they are reported in our consolidated financial statements and how their fair values are measured.

### *Commodity Price Risk*

Our strategy is to obtain competitive prices for our products and allow operating results to reflect market price movements dictated by supply and demand. However, management will periodically protect prices on forecasted sales to support cash flow and liquidity, as deemed appropriate. We may use a variety of commodity derivative instruments, including futures, forwards, swaps and combinations of options, as part of an overall program to manage commodity price risk in our business. Our consolidated results for 2021, 2020 and 2019 were impacted by crude oil, natural gas and natural gas liquid derivatives related to a portion of our forecasted United States sales.

As of December 31, 2021, we had various open commodity derivatives. Based on the December 31, 2021 published NYMEX WTI and natural gas futures prices, a hypothetical 10% change (per bbl for crude oil and per MMBtu for natural gas) would change the fair values of our $7 million net liability position to the following:

| *(In millions)* | Fair Value at December 31, 2021 | Hypothetical Price Increase of 10% | Hypothetical Price Decrease of 10% |
|---|---|---|---|
| Derivative asset (liability) – Crude Oil | $ (8) | $ (31) | $ 9 |
| Derivative asset (liability) – Natural Gas | 1 | — | 1 |
| Total | $ (7) | $ (31) | $ 10 |

### *Interest Rate Risk*

At December 31, 2021 our portfolio of current and long-term debt is comprised of fixed-rate instruments with an outstanding balance of $4.0 billion. Our sensitivity to interest rate movements and corresponding changes in the fair value of our fixed-rate debt portfolio affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices different than carrying value.

At December 31, 2021, we had forward starting interest rate swap agreements with a total notional amount of $295 million designated as cash flow hedges and $375 million not designated as hedges. We utilize cash flow hedges to manage our exposure to interest rate movements by utilizing interest rate swap agreements to hedge variations in cash flows related to 1-month LIBOR component of future lease payments on our future Houston office. A hypothetical 10% change in interest rates would change the fair values of our cash flow hedge and de-designated cash flow hedge positions to the following as of December 31, 2021:

| *(In millions)* | Fair Value at December 31, 2021 | Hypothetical Interest Rate Increase of 10% | Hypothetical Interest Rate Decrease of 10% |
|---|---|---|---|
| Interest rate asset (liability) – designated as cash flow hedges | $ (5) | $ (3) | $ (6) |
| Interest rate asset (liability) – not designated as cash flow hedges | 27 | 33 | 21 |
| Total | $ 22 | $ 30 | $ 15 |

### *Counterparty Risk*

We are also exposed to financial risk in the event of nonperformance by counterparties. If commodity prices fall below certain levels, some of our counterparties may experience liquidity problems and may not be able to meet their financial obligations to us. We review the creditworthiness of counterparties and use master netting agreements when appropriate.

## Item 8. Financial Statements and Supplementary Data

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## Management's Responsibilities for Financial Statements

To the Stockholders of Marathon Oil Corporation:

The accompanying consolidated financial statements of Marathon Oil Corporation and its consolidated subsidiaries ("Marathon Oil") are the responsibility of management and have been prepared in conformity with accounting principles generally accepted in the United States. They necessarily include some amounts that are based on best judgments and estimates. The financial information displayed in other sections of this Annual Report on Form 10-K is consistent with these consolidated financial statements.

Marathon Oil seeks to assure the objectivity and integrity of its financial records by careful selection of its managers, by organization arrangements that provide an appropriate division of responsibility and by communications programs aimed at assuring that its policies and methods are understood throughout the organization.

The Board of Directors pursues its oversight role in the area of financial reporting and internal control over financial reporting through its Audit and Finance Committee. This Committee, composed solely of independent directors, regularly meets (jointly and separately) with the independent registered public accounting firm, management and internal auditors to monitor the proper discharge by each of their responsibilities relative to internal accounting controls and the consolidated financial statements.

| /s/ Lee M. Tillman | /s/ Dane E. Whitehead |
|---|---|
| *Chairman, President and Chief Executive Officer* | *Executive Vice President and Chief Financial Officer* |

## Management's Report on Internal Control over Financial Reporting

To the Stockholders of Marathon Oil Corporation:

Marathon Oil's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13(a) – 15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. 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.

An evaluation of the design and effectiveness of our internal control over financial reporting, based on the 2013 framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer. Based on the results of this evaluation, Marathon Oil's management concluded that its internal control over financial reporting was effective as of December 31, 2021.

The effectiveness of Marathon Oil's internal control over financial reporting as of December 31, 2021 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

| /s/ Lee M. Tillman | /s/ Dane E. Whitehead |
|---|---|
| *Chairman, President and Chief Executive Officer* | *Executive Vice President and Chief Financial Officer* |

## *Report of Independent Registered Public Accounting Firm*

To the Board of Directors and Stockholders of Marathon Oil Corporation

### *Opinions on the Financial Statements and Internal Control over Financial Reporting*

We have audited the accompanying consolidated balance sheet of Marathon Oil Corporation and its subsidiaries (the "Company") as of December 31, 2021 and 2020, and the related consolidated statements of income, of comprehensive income, of stockholders' equity and of cash flows for each of the three years in the period ended December 31, 2021, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

### *Basis for Opinions*

The Company's management is responsible for these consolidated financial statements, 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 Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements 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. 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

### *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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

***Critical Audit Matters***

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 (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

*The Impact of Proved Oil and Condensate, Natural Gas Liquids (NGLs) and Natural Gas Reserves on Proved Oil and Gas Properties, Net*

As described in Notes 1 and 11 to the consolidated financial statements, the Company's consolidated property, plant and equipment, net balance was $14,499 million as of December 31, 2021, and depreciation, depletion, and amortization (DD&A) expense for the year ended December 31, 2021 was $2,066 million. The Company follows the successful efforts method of accounting for its oil and gas producing activities. Under this method, capitalized costs to acquire oil and natural gas properties are depreciated and depleted on a units-of-production basis based on estimated proved reserves. Capitalized costs of exploratory wells and development costs are depreciated and depleted on a units-of-production basis based on estimated proved developed reserves. As disclosed by management, reserve estimates may change as additional information becomes available and as contractual, operational, economic and political conditions change. The data for a given reservoir may also change over time as a result of numerous factors including, but not limited to, additional development activity and future development costs, production history and continual reassessment of the viability of future production volumes under varying economic conditions. The estimates of oil and condensate, NGLs and natural gas reserves have been developed by specialists, specifically petroleum engineers and geoscientists.

The principal considerations for our determination that performing procedures relating to the impact of proved oil and condensate, NGLs and natural gas reserves on proved oil and natural gas properties, net is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the estimates of proved oil and condensate, NGLs and natural gas reserves, which in turn led to (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to the data, methods, and assumptions used by management and its specialists in developing the estimates of proved oil and condensate, NGLs, and natural gas reserves volumes.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved oil and condensate, NGLs, and natural gas reserves. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the proved oil and condensate, NGLs, and natural gas reserve volumes. As a basis for using this work, the specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists and an evaluation of the specialists' findings.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 17, 2022

We have served as the Company's auditor since 1982.

*MARATHON OIL CORPORATION*
*Consolidated Statements of Income*

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions, except per share data)* | **2021** | **2020** | **2019** |
| **Revenues and other income:** | | | |
| Revenues from contracts with customers | $ 5,601 | $ 3,097 | $ 5,063 |
| Net gain (loss) on commodity derivatives | (383) | 116 | (72) |
| Income (loss) from equity method investments | 253 | (161) | 87 |
| Net gain (loss) on disposal of assets | (19) | 9 | 50 |
| Other income | 15 | 25 | 62 |
| Total revenues and other income | 5,467 | 3,086 | 5,190 |
| **Costs and expenses:** | | | |
| Production | 534 | 555 | 712 |
| Shipping, handling and other operating | 727 | 596 | 605 |
| Exploration | 136 | 181 | 149 |
| Depreciation, depletion and amortization | 2,066 | 2,316 | 2,397 |
| Impairments | 60 | 144 | 24 |
| Taxes other than income | 345 | 200 | 311 |
| General and administrative | 291 | 274 | 356 |
| Total costs and expenses | 4,159 | 4,266 | 4,554 |
| **Income (loss) from operations** | 1,308 | (1,180) | 636 |
| Net interest and other | (188) | (256) | (244) |
| Other net periodic benefit (costs) credits | 5 | (1) | 3 |
| Loss on early extinguishment of debt | (121) | (28) | (3) |
| **Income (loss) before income taxes** | 1,004 | (1,465) | 392 |
| Provision (benefit) for income taxes | 58 | (14) | (88) |
| **Net income (loss)** | $ 946 | $ (1,451) | $ 480 |
| **Net income (loss) per share:** | | | |
| Basic | $ 1.20 | $ (1.83) | $ 0.59 |
| Diluted | $ 1.20 | $ (1.83) | $ 0.59 |
| **Weighted average common shares outstanding:** | | | |
| Basic | 787 | 792 | 810 |
| Diluted | 788 | 792 | 810 |

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

*MARATHON OIL CORPORATION*
*Consolidated Statements of Comprehensive Income*

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | **2021** | **2020** | **2019** |
| Net income (loss) | $ 946 | $ (1,451) | $ 480 |
| Other comprehensive income (loss), net of tax | | | |
| Change in actuarial gain (loss) and other for postretirement and postemployment plans | 14 | (30) | 16 |
| Change in derivative hedges unrecognized gain (loss) | 23 | (2) | 2 |
| Reclassification of de-designated forward interest rate swaps | (28) | — | — |
| Foreign currency translation adjustment related to sale of U.K. business | — | — | 23 |
| Other | — | — | 1 |
| Other comprehensive income (loss) | 9 | (32) | 42 |
| Comprehensive income (loss) | $ 955 | $ (1,483) | $ 522 |

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

*MARATHON OIL CORPORATION*
*Consolidated Balance Sheet*

| | December 31, | |
|---|---|---|
| *(In millions, except par values and share amounts)* | **2021** | **2020** |
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 580 | $ 742 |
| Receivables, less reserve of $15 and $22 | 1,142 | 747 |
| Inventories | 77 | 76 |
| Other current assets | 22 | 47 |
| Total current assets | 1,821 | 1,612 |
| Equity method investments | 450 | 447 |
| Property, plant and equipment, less accumulated depreciation, depletion and amortization of $22,412 and $20,358 | 14,499 | 15,638 |
| Other noncurrent assets | 224 | 259 |
| Total assets | $ 16,994 | $ 17,956 |
| **Liabilities** | | |
| Current liabilities: | | |
| Accounts payable | $ 1,110 | $ 837 |
| Payroll and benefits payable | 74 | 57 |
| Accrued taxes | 157 | 72 |
| Other current liabilities | 260 | 247 |
| Long-term debt due within one year | 36 | — |
| Total current liabilities | 1,637 | 1,213 |
| Long-term debt | 3,978 | 5,404 |
| Deferred tax liabilities | 136 | 163 |
| Defined benefit postretirement plan obligations | 137 | 180 |
| Asset retirement obligations | 288 | 241 |
| Deferred credits and other liabilities | 132 | 194 |
| Total liabilities | 6,308 | 7,395 |
| Commitments and contingencies | | |
| **Stockholders' Equity** | | |
| Preferred stock – no shares issued or outstanding (no par value, 26 million shares authorized) | — | — |
| Common stock: | | |
| Issued – 937 million shares (par value $1 per share, 1.925 billion shares authorized at December 31, 2021 and December 31, 2020) | 937 | 937 |
| Held in treasury, at cost – 194 million shares and 148 million shares | (4,825) | (4,089) |
| Additional paid-in capital | 7,221 | 7,174 |
| Retained earnings | 7,271 | 6,466 |
| Accumulated other comprehensive income | 82 | 73 |
| Total stockholders' equity | 10,686 | 10,561 |
| Total liabilities and stockholders' equity | $ 16,994 | $ 17,956 |

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

## *MARATHON OIL CORPORATION*
## *Consolidated Statements of Cash Flows*

| *(In millions)* | Year Ended December 31, 2021 | 2020 | 2019 |
|---|---|---|---|
| ***Increase (decrease) in cash and cash equivalents*** | | | |
| **Operating activities:** | | | |
| Net income (loss) | $ 946 | $ (1,451) | $ 480 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Depreciation, depletion and amortization | 2,066 | 2,316 | 2,397 |
| Impairments | 60 | 144 | 24 |
| Exploratory dry well costs and unproved property impairments | 125 | 159 | 114 |
| Net (gain) loss on disposal of assets | 19 | (9) | (50) |
| Loss on early extinguishment of debt | 121 | 28 | 3 |
| Deferred income taxes | (27) | (22) | (34) |
| Unrealized (gain) loss on derivative instruments, net | (16) | 27 | 124 |
| Pension and other post retirement benefits, net | (31) | (43) | (52) |
| Stock-based compensation | 40 | 57 | 60 |
| Equity method investments, net | (76) | 210 | 18 |
| Changes in: | | | |
| Current receivables | (389) | 367 | 52 |
| Inventories | (1) | (4) | 3 |
| Current accounts payable and accrued liabilities | 369 | (381) | (187) |
| Other current assets and liabilities | 46 | 75 | (4) |
| All other operating, net | (13) | — | (199) |
| Net cash provided by operating activities | 3,239 | 1,473 | 2,749 |
| **Investing activities:** | | | |
| Additions to property, plant and equipment | (1,046) | (1,343) | (2,550) |
| Additions to other assets | — | 15 | 36 |
| Acquisitions, net of cash acquired | (47) | (1) | (293) |
| Disposal of assets, net of cash transferred to the buyer | 22 | 18 | (76) |
| Equity method investments - return of capital | 61 | 7 | 64 |
| All other investing, net | — | 1 | 1 |
| Net cash used in investing activities | (1,010) | (1,303) | (2,818) |
| **Financing activities:** | | | |
| Borrowings | — | 400 | 600 |
| Debt repayments | (1,400) | (500) | (600) |
| Debt extinguishment costs | (117) | (27) | (2) |
| Purchases of common stock | (734) | (92) | (362) |
| Dividends paid | (141) | (64) | (162) |
| All other financing, net | 1 | (3) | (9) |
| Net cash used in financing activities | (2,391) | (286) | (535) |
| **Net increase (decrease) in cash and cash equivalents** | (162) | (116) | (604) |
| **Cash and cash equivalents at beginning of period** | 742 | 858 | 1,462 |
| **Cash and cash equivalents at end of period** | $ 580 | $ 742 | $ 858 |

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

# *MARATHON OIL CORPORATION*
## *Consolidated Statements of Stockholders' Equity*

| | Total Equity of Marathon Oil Stockholders | | | | | | |
|---|---|---|---|---|---|---|---|
| *(In millions)* | Preferred Stock | Common Stock | Treasury Stock | Additional Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total Equity |
| **December 31, 2018 Balance** | $ — | $ 937 | $ (3,816) | $ 7,238 | $ 7,706 | $ 63 | $ 12,128 |
| Cumulative-effect adjustment (Note 2) | — | — | — | — | (31) | — | (31) |
| Shares issued - stock-based compensation | — | — | 89 | (26) | — | — | 63 |
| Shares repurchased | — | — | (362) | — | — | — | (362) |
| Stock-based compensation | — | — | — | (5) | — | — | (5) |
| Net income (loss) | — | — | — | — | 480 | — | 480 |
| Other comprehensive income (loss) | — | — | — | — | — | 42 | 42 |
| Dividends paid ($0.20 per share) | — | — | — | — | (162) | — | (162) |
| **December 31, 2019 Balance** | $ — | $ 937 | $ (4,089) | $ 7,207 | $ 7,993 | $ 105 | $ 12,153 |
| Cumulative-effect adjustment (Note 2) | — | — | — | — | (12) | — | (12) |
| Shares issued - stock-based compensation | — | — | 91 | (60) | — | — | 31 |
| Shares repurchased | — | — | (91) | — | — | — | (91) |
| Stock-based compensation | — | — | — | 27 | — | — | 27 |
| Net income (loss) | — | — | — | — | (1,451) | — | (1,451) |
| Other comprehensive income (loss) | — | — | — | — | — | (32) | (32) |
| Dividends paid ($0.08 per share) | — | — | — | — | (64) | — | (64) |
| **December 31, 2020 Balance** | $ — | $ 937 | $ (4,089) | $ 7,174 | $ 6,466 | $ 73 | $ 10,561 |
| Shares issued - stock-based compensation | — | — | (2) | 10 | — | — | 8 |
| Shares repurchased | — | — | (734) | — | — | — | (734) |
| Stock-based compensation | — | — | — | 37 | — | — | 37 |
| Net income (loss) | — | — | — | — | 946 | — | 946 |
| Other comprehensive income (loss) | — | — | — | — | — | 9 | 9 |
| Dividends paid ($0.18 per share) | — | — | — | — | (141) | — | (141) |
| **December 31, 2021 Balance** | $ — | $ 937 | $ (4,825) | $ 7,221 | $ 7,271 | $ 82 | $ 10,686 |

| *(Shares in millions)* | Preferred Stock | Common Stock | Treasury Stock |
|---|---|---|---|
| **December 31, 2018 Balance** | — | 937 | 118 |
| Shares issued - stock-based compensation | — | — | (2) |
| Shares repurchased | — | — | 25 |
| **December 31, 2019 Balance** | — | 937 | 141 |
| Shares issued - stock-based compensation | — | — | (3) |
| Shares repurchased | — | — | 10 |
| **December 31, 2020 Balance** | — | 937 | 148 |
| Shares issued - stock-based compensation | — | — | — |
| Shares repurchased | — | — | 46 |
| **December 31, 2021 Balance** | — | 937 | 194 |

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

## 1. Summary of Principal Accounting Policies

We are an independent exploration and production company engaged in exploration, production and marketing of crude oil and condensate, NGLs and natural gas; as well as production and marketing of products manufactured from natural gas, such as LNG and methanol, in E.G.

***Basis of presentation and principles applied in consolidation*** – These consolidated financial statements, including notes, have been prepared in accordance with U.S. GAAP. These consolidated financial statements include the accounts of our controlled subsidiaries. Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis.

*Equity method investments* – Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting. This includes entities in which we hold majority ownership but the minority stockholders have substantive participating rights in the investee. Income from equity method investments represents our proportionate share of net income generated by the equity method investees and is reflected in revenues and other income in our consolidated statements of income. Equity method investments are included as noncurrent assets on the consolidated balance sheet.

Equity method investments are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value may have occurred. When a loss is deemed to have occurred and is other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in income.

***Use of estimates*** – The preparation of financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods.

Estimated quantities of crude oil and condensate, NGLs and natural gas reserves is a significant estimate that requires judgment. All of the reserve data included in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and condensate, NGLs and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and condensate, NGLs and natural gas reserves. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil and condensate, NGLs and natural gas that are ultimately recovered. See unaudited Supplementary Data – **Supplementary Information on Oil and Gas Producing Activities** for further detail.

Other items subject to estimates and assumptions include the carrying amounts of property, plant and equipment, asset retirement obligations, goodwill, valuation of derivative instruments and valuation allowances for deferred income tax assets, among others. Although we believe these estimates are reasonable, actual results could differ from these estimates.

***Foreign currency transactions*** – The U.S. dollar is the functional currency of our foreign operating subsidiaries. Foreign currency transaction gains and losses are included in net income.

***Revenue recognition*** – Revenues associated with the sales of crude oil and condensate, NGLs and natural gas are recognized when our performance obligation is satisfied, which typically occurs at the point where control transfers to the customer based on contract terms. Revenue is measured as the amount the company expects to receive in exchange for transferring commodities to the customer. Our hydrocarbon sales are typically based on prevailing market-based prices and may include quality or location differential adjustments. Payment is generally due within 30 days of delivery.

We typically incur shipping and handling costs prior to control transferring to the customer and account for these activities as fulfillment costs. These costs are reflected in shipping, handling and other operating expense in our consolidated statement of income.

Our U.S. production of crude oil and condensate, NGLs and natural gas is generally sold immediately and transported to market. In our international segment, liquid hydrocarbon production may be stored as inventory and sold at a later time.

***Cash and cash equivalents*** – Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with original maturities of three months or less.

***Accounts receivable*** – The majority of our receivables are from purchasers of commodities or joint interest owners in properties we operate, both of which are recorded at estimated or invoiced amounts and do not bear interest. We often have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We conduct credit reviews of commodity purchasers prior to making commodity sales to new customers or increasing credit for existing customers. Based on these reviews, we may require a standby letter of credit or a financial guarantee. We routinely assess the collectability of receivable balances to determine if the amount of the reserve for credit losses is sufficient.

***Inventories*** – Crude oil and natural gas are recorded at weighted average cost and carried at the lower of cost or net realizable value. Supplies and other items consist principally of tubular goods and equipment, which are valued at weighted average cost and reviewed periodically for obsolescence or impairment when market conditions indicate.

We may enter into a contract to sell a particular quantity and quality of crude oil at a specified location and date to a particular counterparty, and simultaneously agree to buy a particular quantity and quality of the same commodity at a specified location on the same or another specified date from the same counterparty. We account for such matching buy/sell arrangements as exchanges of inventory.

***Derivative instruments*** – We may use derivatives to manage a portion of our exposure to commodity price risk, commodity locational risk and interest rate risk. All derivative instruments are recorded at fair value. Commodity derivatives and interest rate swaps are reflected on our consolidated balance sheet on a net basis by counterparty, as they are governed by master netting agreements. Cash flows related to derivatives used to manage commodity price risk, and interest rate risk are classified in operating activities. Our derivative instruments contain no significant contingent credit features.

*Cash flow hedges* – We may use interest rate derivative instruments to manage the risk of interest rate changes during the period prior to anticipated borrowings as well as to stabilize future lease payments on our Houston office, and designate them as cash flow hedges. Derivative instruments designated as cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The changes in the fair value of a qualifying cash flow hedge are recorded in other comprehensive income until the hedged transaction affects earnings and are then reclassified into net income. Ineffective portions of a cash flow hedge are no longer measured or disclosed separately. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable or the cash flow hedge is no longer expected to be highly effective, subsequent changes in fair value of the derivatives instrument are recorded in net income.

*Derivatives not designated as hedges* – Derivatives that are not designated as hedges may include commodity derivatives used primarily to manage price and locational risks on the forecasted sale of crude oil, NGLs and natural gas that we produce. Changes in the fair value of derivatives not designated as hedges are recognized immediately in net income.

***Concentrations of credit risk*** – All of our financial instruments, including derivatives, involve elements of credit and market risk. The most significant portion of our credit risk relates to nonperformance by counterparties. The counterparties to our financial instruments consist primarily of major financial institutions and companies within the energy industry. To manage counterparty risk associated with financial instruments, we select and monitor counterparties based on our assessment of their financial strength and on credit ratings, if available. Additionally, we limit the level of exposure with any single counterparty.

***Fair value transfer*** – We recognize transfers between levels of the fair value hierarchy as of the end of the reporting period.

***Property, plant and equipment*** – We use the successful efforts method of accounting for oil and gas producing activities.

*Property acquisition costs* – Costs to acquire mineral interests in oil and natural gas properties, to drill exploratory wells in progress and those that find proved reserves and to drill development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves but cannot yet be classified as proved are capitalized if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended exploratory well costs is monitored continuously and reviewed at least quarterly.

*Depreciation, depletion and amortization* – Capitalized costs to acquire oil and natural gas properties are depreciated and depleted on a units-of-production basis based on estimated proved reserves. Capitalized costs of exploratory wells and development costs are depreciated and depleted on a units-of-production basis based on estimated proved developed reserves. Support equipment and other property, plant and equipment related to oil and gas producing activities, as well as property, plant and equipment unrelated to oil and gas producing activities, are recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets. The table below summarizes these assets by type, useful life and the net asset balance as of the periods presented.

| | | December 31, | |
|---|---|---|---|
| **Type of Asset** | **Range of Useful Lives** | **2021** | **2020** |
| | | *(in millions)* | |
| Office furniture, equipment and computer hardware | 4 to 15 years | $ 41 | $ 52 |
| Pipelines | 5 to 40 years | $ 10 | $ 11 |
| Plants, facilities and infrastructure | 3 to 40 years | $ 1,496 | $ 1,463 |

*Impairments* – We evaluate our oil and gas producing properties, including capitalized costs of exploratory wells and development costs, for impairment of value whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. Oil and gas producing properties are reviewed for impairment on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure or contractual terms that cause economic interdependency amongst separate, discrete fields. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows or, if available, comparable market value. We evaluate our unproved property investment and record impairment based on time or geologic factors. Information such as drilling results, reservoir performance, seismic interpretation, lease expiration dates or future plans to develop acreage is also considered. When unproved property investments are deemed to be impaired, this amount is reported in exploration expenses in our consolidated statements of income.

*Dispositions* – When property, plant and equipment depreciated on an individual basis is sold or otherwise disposed of, any gains or losses are reflected in net gain (loss) on disposal of assets in our consolidated statements of income. Gains on the disposal of property, plant and equipment are recognized when earned, which is generally at the time of closing. If a loss on disposal is expected, such losses are recognized either when the assets are classified as held for sale, or are measured using a probability weighted income approach based on both the anticipated sales price and a held-for-use model depending on timing of the sale. Proceeds from the disposal of a portion of property, plant and equipment depreciated on a group basis are credited to accumulated depreciation, depletion and amortization with no immediate effect on net income until net book value is reduced to zero.

***Goodwill*** – Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Such goodwill is not amortized, but rather is tested for impairment annually and when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to a reporting unit. The fair value of a reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then the recorded goodwill is impaired to its implied fair value with a charge to impairments. In 2020, our goodwill was fully impaired. See **Note 15** for further information.

***Environmental costs*** – We provide for remediation costs and penalties when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. The timing of remediation accruals coincides with completion of a feasibility study or the commitment to a formal plan of action. Remediation liabilities are accrued based on estimates of known environmental exposure and are discounted when the estimated amounts are reasonably fixed or reliably determinable. Environmental expenditures are capitalized only if the costs mitigate or prevent future contamination or if the costs improve the environmental safety or efficiency of the existing assets.

***Asset retirement obligations*** – The fair value of asset retirement obligations is recognized in the period in which the obligations are incurred if a reasonable estimate of fair value can be made. Our asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities. Asset retirement obligations for such facilities include costs to dismantle and relocate or dispose of production platforms, gathering systems, wells and related structures and restoration costs of land, including those leased. Estimates of these costs are developed for each property based on the type of production facilities and equipment, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering professionals.

Inflation rates and credit-adjusted-risk-free interest rates are used to estimate the fair value of asset retirement obligations. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis based on estimated proved developed reserves for oil and gas production facilities, while accretion of the liability occurs over the useful lives of the assets.

***Income taxes*** – Deferred tax assets and liabilities, measured at enacted tax rates, are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. We routinely assess the realizability of our deferred tax assets based on several interrelated factors and reduce such assets 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. These factors include whether we are in a cumulative loss position in recent years, our reversal of temporary differences, and our expectation to generate sufficient future taxable income. We use the liability method in determining our provision and liabilities for our income taxes, under which current and deferred tax liabilities and assets are recorded in accordance with enacted tax laws and rates.

***Stock-based compensation arrangements*** – The fair value of stock options is estimated on the date of grant using the Black-Scholes option pricing model. The model employs various assumptions, based on management's best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock option award. Of the required assumptions, the expected volatility of our stock price and the stock price in relation to the strike price have the most significant impact on the fair value calculation. We have utilized historical data and analyzed current information which reasonably support these assumptions.

The fair value of our restricted stock awards, restricted stock units and Director restricted stock units is determined based on the market value of our common stock on the date of grant. Restricted stock awards, restricted stock units and Director restricted stock units are removed from Treasury Stock at grant, vesting and distribution, respectively.

The fair value of our cash-settled stock-based performance units is estimated using the Monte Carlo simulation method. Since these awards are settled in cash at the end of a defined performance period, they are classified as a liability and are re-measured quarterly until settlement. The fair value of our free cash flow cash-settled stock-based performance units is estimated by multiplying the estimated vesting percentage by our common stock's closing stock price plus accumulated dividend equivalents. Since these awards are settled in cash at the end of a defined performance period, they are classified as a liability and are re-measured quarterly until settlement. The fair value of our stock-settled stock-based performance units is estimated using the Monte Carlo simulation method at grant date only. Since these awards are settled in stock, they are classified as equity.

Our stock-based compensation expense is recognized based on management's best estimate of the awards that are expected to vest, using the straight-line attribution method for all service-based awards with a graded vesting feature. If actual forfeiture results are different than expected, adjustments to recognized compensation expense may be required in future periods.

## 2. New Accounting Standards

No new accounting standards were adopted during the year ended 2021 that had a material impact on our consolidated financial statements.

### 3. Income (loss) and Dividends per Common Share

Basic income (loss) per share is based on the weighted average number of common shares outstanding. Diluted income (loss) per share assumes exercise of stock options in all periods, provided the effect is not antidilutive. The per share calculations below exclude 4 million, 7 million and 6 million stock options for 2021, 2020 and 2019 that were antidilutive.

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions, except per share data)* | 2021 | 2020 | 2019 |
| Net income (loss) | $ 946 | $ (1,451) | $ 480 |
| Weighted average common shares outstanding | 787 | 792 | 810 |
| Effect of dilutive securities | 1 | — | — |
| Weighted average common shares, diluted | 788 | 792 | 810 |
| **Net income (loss) per share:** | | | |
| Basic | $ 1.20 | $ (1.83) | $ 0.59 |
| Diluted | $ 1.20 | $ (1.83) | $ 0.59 |
| **Dividends per share** | $ 0.18 | $ 0.08 | $ 0.20 |

### 4. Acquisitions

*United States Segment*

In the fourth quarter of 2019, we acquired approximately 40,000 net acres in a Texas Delaware oil play in West Texas from multiple sellers for $106 million. We accounted for these transactions as an asset acquisition, allocating the purchase price to unproved property within property, plant and equipment.

During the fourth quarter of 2019, we acquired a 100% working interest in approximately 18,000 net acres in the Eagle Ford from Rocky Creek Resources, LLC and RCR Midstream, LLC for $191 million in cash, subject to post-closing adjustments. We accounted for this transaction as a business combination, with the entire purchase price allocated between proved property, unproved property and other assets, all within property, plant and equipment.

The fair values of the Rocky Creek assets were measured using the market approach, specifically the market comparable technique. The fair values were based on market-corroborated inputs, which were derived from observable market data; such inputs represent Level 2 inputs. The transaction was immaterial to generate any pro forma effects on our consolidated financial statements.

### 5. Dispositions

*International Segment*

On July 1, 2019, we closed on the sale of our U.K. business (Marathon Oil U.K. LLC and Marathon Oil West of Shetlands Limited) for proceeds of $95 million, which includes the assumption by RockRose Energy PLC ("RoseRock") of the U.K. business' cash equivalents, working capital and asset retirement obligation balances. Income before income taxes relating to our U.K. business during the year ended December 31, 2019 was $33 million. See **Note 20** for additional details on the defined benefit pension plan as it relates to this disposition.

In the second quarter of 2019, we closed on the sale of our 15% non-operated interest in the Atrush block in Kurdistan for proceeds of $63 million, before closing adjustments.

### 6. Revenues

The majority of our revenues are derived from the sale of crude oil and condensate, NGLs and natural gas under spot and term agreements with our customers in the United States and various international locations.

As of December 31, 2021 and December 31, 2020, receivables from contracts with customers, included in receivables, less reserves for credit losses were $961 million and $572 million, respectively.

The following tables present our revenues from contracts with customers disaggregated by product type and geographic areas.

*United States*

| | Year Ended December 31, 2021 | | | | | |
|---|---|---|---|---|---|---|
| *(In millions)* | Eagle Ford | Bakken | Oklahoma | Northern Delaware | Other U.S. | Total |
| Crude oil and condensate | $ 1,435 | $ 1,777 | $ 299 | $ 314 | $ 100 | $ 3,925 |
| Natural gas liquids | 161 | 239 | 189 | 47 | 17 | 653 |
| Natural gas | 159 | 119 | 280 | 55 | 19 | 632 |
| Other | 8 | — | — | — | 116 | 124 |
| Revenues from contracts with customers | $ 1,763 | $ 2,135 | $ 768 | $ 416 | $ 252 | $ 5,334 |

| | Year Ended December 31, 2020 | | | | | |
|---|---|---|---|---|---|---|
| *(In millions)* | Eagle Ford | Bakken | Oklahoma | Northern Delaware | Other U.S. | Total |
| Crude oil and condensate | $ 830 | $ 984 | $ 235 | $ 204 | $ 69 | $ 2,322 |
| Natural gas liquids | 74 | 54 | 89 | 20 | 6 | 243 |
| Natural gas | 86 | 34 | 127 | 18 | 10 | 275 |
| Other | 6 | — | — | — | 78 | 84 |
| Revenues from contracts with customers | $ 996 | $ 1,072 | $ 451 | $ 242 | $ 163 | $ 2,924 |

| | Year Ended December 31, 2019 | | | | | |
|---|---|---|---|---|---|---|
| *(In millions)* | Eagle Ford | Bakken | Oklahoma | Northern Delaware | Other U.S. | Total |
| Crude oil and condensate | $ 1,358 | $ 1,686 | $ 425 | $ 316 | $ 102 | $ 3,887 |
| Natural gas liquids | 114 | 46 | 116 | 26 | 5 | 307 |
| Natural gas | 121 | 39 | 156 | 16 | 17 | 349 |
| Other | 7 | — | — | — | 52 | 59 |
| Revenues from contracts with customers | $ 1,600 | $ 1,771 | $ 697 | $ 358 | $ 176 | $ 4,602 |

*International*

| | Year Ended December 31, | |
|---|---|---|
| | 2021 | 2020 |
| *(In millions)* | E.G. | E.G. |
| Crude oil and condensate | $ 240 | $ 140 |
| Natural gas liquids | 2 | 4 |
| Natural gas | 23 | 29 |
| Other | 2 | — |
| Revenues from contracts with customers | $ 267 | $ 173 |

| | Year Ended December 31, 2019 | | | |
|---|---|---|---|---|
| *(In millions)* | **E.G.** | **U.K.** | **Other International** | **Total** |
| Crude oil and condensate | $ 271 | $ 107 | $ 20 | $ 398 |
| Natural gas liquids | 4 | 1 | — | 5 |
| Natural gas | 32 | 12 | — | 44 |
| Other | — | 14 | — | 14 |
| Revenues from contracts with customers | $ 307 | $ 134 | $ 20 | $ 461 |

Customers and their respective affiliates who accounted for 10% or more of our total commodity sales were as follows:

| | December 31, | | |
|---|---|---|---|
| | **2021** | **2020** | **2019** |
| **Percentage of Total Commodity Sales** | | | |
| Marathon Petroleum Corporation | 17 % | 13 % | 13 % |
| Valero Marketing and Supply | 10 % | N/A | 11 % |
| Koch Resources LLC | N/A | 12 % | 13 % |
| Shell Trading | N/A | N/A | 10 % |

The pricing in our hydrocarbon sales agreements are variable, determined using various published benchmarks which are adjusted for negotiated quality and location differentials. As a result, revenue collected under our agreements with customers is highly dependent on the market conditions and may fluctuate considerably as the hydrocarbon market prices rise or fall. Typically, our customers pay us monthly, within a short period of time after we deliver the hydrocarbon products. As such, we do not have any financing element associated with our contracts. We do not have any issues related to returns or refunds, as product specifications are standardized for the industry and are typically measured when transferred to a common carrier or midstream entity, and other contractual mechanisms (e.g., price adjustments) are used when products do not meet those specifications.

In limited cases, we may also collect advance payments from customers as stipulated in our agreements; payments in excess of recognized revenue are recorded as contract liabilities on our consolidated balance sheet.

Under our hydrocarbon sales agreements, the entire consideration amount is variable either due to pricing and/or volumes. We recognize revenue in the amount of variable consideration allocated to distinct units of hydrocarbons transferred to a customer. Such allocation reflects the amount of total consideration we expect to collect for completed deliveries of hydrocarbons and the terms of variable payment relate specifically to our efforts to satisfy the performance obligations under these contracts. Our performance obligations under our hydrocarbon sales agreements are to deliver either the entire production from the dedicated wells or specified contractual volumes of hydrocarbons.

We often serve as the operator for jointly owned oil and gas properties. As part of this role, we perform activities to explore, develop and produce oil and gas properties in accordance with the joint operating arrangements. Other working interest owners reimburse us for costs incurred based on our agreements. We determined that these activities are not performed as part of customer relationships and such reimbursements will continue to not be recorded as revenues within the scope of the revenue accounting standard.

In addition, we commonly market the share of production belonging to other working interest owners as the operator of jointly owned oil and gas properties. We concluded that those marketing activities are carried out as part of the collaborative arrangement. Therefore, we act as a principal only in regards to the sale of our share of production and recognize revenue for the volumes associated with our net production.

*Crude oil and condensate*

For the crude sales agreements, we satisfy our performance obligations and recognize revenue once customers take control of the crude at the designated delivery points, which include pipelines, trucks or vessels.

*Natural gas and NGLs*

When selling natural gas and NGLs, we engage midstream entities to process our production stream by separating natural gas from the NGLs. Frequently, these midstream entities also purchase our natural gas and NGLs under the same agreements.

In these situations, we determined the performance obligation is complete and satisfied at the tailgate of the processing plant when the natural gas and NGLs become identifiable and measurable products. We determined the plant tailgate is the point in time where control is transferred to midstream entities and they are entitled to significant risks and rewards of ownership of the natural gas and NGLs.

The amounts due to midstream entities for gathering and processing services are recognized as shipping and handling cost, since we make those payments in exchange for distinct services. Under some of our natural gas processing agreements, we have an option to take the processed natural gas and NGLs in-kind and sell to customers other than the processing company. In those circumstances, our performance obligations are complete after delivering the processed hydrocarbons to the customer at the designated delivery points, which may be the tailgate of the processing plant or an alternative delivery point requested by the customer.

We have “percentage-of-proceeds” arrangements with some midstream entities where they retain a percentage of the proceeds collected for selling our processed natural gas and NGLs as compensation for their processing and marketing services. We recognize revenue for the gross sales volumes and recognize the proceeds retained by midstream companies as shipping and handling cost.

## 7. Segment Information

We have two reportable operating segments. Both of these segments are organized and managed based upon geographic location and the nature of the products and services offered.

- United States (“U.S.”) – explores for, produces and markets crude oil and condensate, NGLs and natural gas in the United States
- International (“Int’l”) – produces and markets crude oil and condensate, NGLs and natural gas outside of the United States as well as produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.

Segment income represents income which excludes certain items not allocated to our operating segments, net of income taxes. A portion of our corporate and operations general and administrative support costs are not allocated to the operating segments. These unallocated costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate and operations support activities. Additionally, items which affect comparability such as: gains or losses on dispositions, impairments of proved and certain unproved properties, goodwill and equity method investments, unrealized gains or losses on commodity derivative instruments, gains or losses on interest rate derivative instruments, effects of pension settlements and curtailments, or other items (as determined by the chief operating decision maker (CODM)) are not allocated to operating segments.

| *(In millions)* | Year Ended December 31, 2021 U.S. | Int'l | Not Allocated to Segments | | Total |
|---|---|---|---|---|---|
| Revenues from contracts with customers | $ 5,334 | $ 267 | $ — | | $ 5,601 |
| Net gain (loss) on commodity derivatives | (399) | — | 16 | (b) | (383) |
| Income (loss) from equity method investments | — | 253 | — | | 253 |
| Net loss on disposal of assets | — | — | (19) | (c) | (19) |
| Other income | 7 | 4 | 4 | | 15 |
| Less costs and expenses: | | | | | |
| Production | 480 | 54 | — | | 534 |
| Shipping, handling and other operating | 686 | 16 | 25 | | 727 |
| Exploration | 65 | — | 71 | (d) | 136 |
| Depreciation, depletion and amortization | 1,972 | 68 | 26 | | 2,066 |
| Impairments | — | — | 60 | (e) | 60 |
| Taxes other than income | 346 | — | (1) | | 345 |
| General and administrative | 107 | 13 | 171 | (f) | 291 |
| Net interest and other | — | — | 188 | (g) | 188 |
| Other net periodic benefit (credit) costs | — | — | (5) | | (5) |
| Loss on early extinguishment of debt | — | — | 121 | (h) | 121 |
| Income tax provision (benefit) | 9 | 56 | (7) | | 58 |
| Segment income (loss) | $ 1,277 | $ 317 | $ (648) | | $ 946 |
| Total assets | $ 15,339 | $ 994 | $ 661 | | $ 16,994 |
| Capital expenditures[(a)] | $ 1,018 | $ — | $ 14 | | $ 1,032 |

(a) Includes accruals and excludes acquisitions.
(b) Unrealized gain on commodity derivative instruments (See **Note 16**).
(c) Includes a $20 million loss associated with a previously divested non-core conventional asset, a $12 million pre-tax loss associated with a reduction in our ownership interest in EG LNG (See **Note 24**) and an $8 million gain on various well bore assignments in Permian and Bakken.
(d) Includes unproved property impairments of $20 million for Louisiana exploration leases and $16 million related to the disposition of a lease in Permian. Also includes $28 million of expense associated with drilled and uncompleted wells, primarily in Permian, due to a change in our plan of development (See **Note 11**).
(e) Includes impairments of $24 million for central facilities in Eagle Ford (See **Note 12**), $5 million for proved properties in Permian (See **Note 12**) and $30 million associated with decommissioning costs for non-producing long-lived assets in GOM (See **Note 12**, **Note 13**, and **Note 26**)
(f) Includes $13 million associated with the termination of an aircraft lease agreement and $12 million arising from severance expenses associated with a workforce reduction.
(g) Includes a $28 million gain on our 2022 interest rate swaps and a $27 million gain on our 2025 interest rate swaps (See **Note 16**).
(h) Represents costs related to a make-whole provision premium and the write off of unamortized discount and issuance costs in regards to the redemption of the 2022 Notes in April 2021 and 2025 Notes in September 2021 (See **Note 18**).

| | Year Ended December 31, 2020 | | | |
|---|---|---|---|---|
| *(In millions)* | **U.S.** | **Int'l** | **Not Allocated to Segments** | **Total** |
| Revenues from contracts with customers | $ 2,924 | $ 173 | $ — | $ 3,097 |
| Net gain (loss) on commodity derivatives | 143 | — | (27) [b] | 116 |
| Income (loss) from equity method investments | — | 10 | (171) [c] | (161) |
| Net gain on disposal of assets | — | — | 9 | 9 |
| Other income | 15 | 7 | 3 | 25 |
| Less costs and expenses: | | | | |
| Production | 494 | 59 | 2 | 555 |
| Shipping, handling and other operating | 534 | 8 | 54 | 596 |
| Exploration | 97 | — | 84 [d] | 181 |
| Depreciation, depletion and amortization | 2,211 | 82 | 23 | 2,316 |
| Impairments | — | — | 144 [e] | 144 |
| Taxes other than income | 193 | — | 7 | 200 |
| General and administrative | 115 | 14 | 145 [f] | 274 |
| Net interest and other | — | — | 256 | 256 |
| Other net periodic benefit (credit) cost | — | — | 1 [g] | 1 |
| Loss on early extinguishment of debt | — | — | 28 | 28 |
| Income tax benefit | (9) | (3) | (2) | (14) |
| Segment income (loss) | $ (553) | $ 30 | $ (928) | $ (1,451) |
| Total assets | $ 16,063 | $ 1,081 | $ 812 | $ 17,956 |
| Capital expenditures[a] | $ 1,137 | $ 1 | $ 13 | $ 1,151 |

(a) Includes accruals and excludes acquisitions.
(b) Unrealized loss on commodity derivative instruments (See **Note 16**).
(c) Partial impairment of investment in equity method investee (See **Note 24**).
(d) Primarily related to unproved property impairments of non-core acreage in our United States segment.
(e) Includes the full impairment of the International reporting unit goodwill of $95 million (See **Note 15**) and proved property impairments of $49 million related to a damaged well in our United States segment.
(f) Includes severance expenses associated with workforce reductions of $17 million.
(g) Includes pension settlement loss of $30 million and pension curtailment gain of 17 million (See **Note 20**).

| *(In millions)* | U.S. | Int'l | Not Allocated to Segments | | Total |
|---|---|---|---|---|---|
| | Year Ended December 31, 2019 | | | | |
| Revenues from contracts with customers | $ 4,602 | $ 461 | $ — | | $ 5,063 |
| Net gain (loss) on commodity derivatives | 52 | — | (124) | (b) | (72) |
| Income (loss) from equity method investments | — | 87 | — | | 87 |
| Net gain on disposal of assets | — | — | 50 | (c) | 50 |
| Other income | 13 | 9 | 40 | | 62 |
| Less costs and expenses: | | | | | |
| Production | 588 | 126 | (2) | | 712 |
| Shipping, handling and other operating | 561 | 26 | 18 | | 605 |
| Exploration | 149 | — | — | | 149 |
| Depreciation, depletion and amortization | 2,250 | 121 | 26 | | 2,397 |
| Impairments | — | — | 24 | (d) | 24 |
| Taxes other than income | 311 | — | — | | 311 |
| General and administrative | 127 | 25 | 204 | | 356 |
| Net interest and other | — | — | 244 | | 244 |
| Other net periodic benefit (credit) cost | — | (3) | — | (e) | (3) |
| Loss on early extinguishment of debt | — | — | 3 | | 3 |
| Income tax provision (benefit) | 6 | 29 | (123) | | (88) |
| Segment income (loss) | $ 675 | $ 233 | $ (428) | | $ 480 |
| Total assets | $ 17,781 | $ 1,530 | $ 934 | | $ 20,245 |
| Capital expenditures[a] | $ 2,550 | $ 16 | $ 25 | | $ 2,591 |

(a) Includes accruals and excludes acquisitions.
(b) Unrealized loss on commodity derivative instruments (See **Note 16**).
(c) Primarily related to the sale of our working interest in the Droshky field (Gulf of Mexico) and the sale of our U.K. business (See **Note 5**).
(d) Primarily a result of anticipated sales of non-core proved properties in our International and United States segments (See **Note 12**).
(e) Includes pension settlement loss of $12 million (See **Note 20**).

The following summarizes property, plant and equipment and equity method investments.

| *(In millions)* | December 31, 2021 | December 31, 2020 |
|---|---|---|
| United States | $ 14,152 | $ 15,224 |
| Equatorial Guinea | 797 | 861 |
| Total long-lived assets | $ 14,949 | $ 16,085 |

## 8. Income Taxes

Income (loss) before income taxes were:

| *(In millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| | Year Ended December 31, | | |
| United States | $ 637 | $ (1,319) | $ 43 |
| Foreign | 367 | (146) | 349 |
| Total | $ 1,004 | $ (1,465) | $ 392 |

Income tax provisions (benefits) were:

| | Year Ended December 31, | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **2021** | | | **2020** | | | **2019** | | |
| *(In millions)* | **Current** | **Deferred** | **Total** | **Current** | **Deferred** | **Total** | **Current** | **Deferred** | **Total** |
| Federal | $ — | $ — | $ — | $ (5) | $ — | $ (5) | $ (116) | $ (3) | $ (119) |
| State and local | 4 | 1 | 5 | (2) | (8) | (10) | 4 | 3 | 7 |
| Foreign | 81 | (28) | 53 | 15 | (14) | 1 | 58 | (34) | 24 |
| Total | $ 85 | $ (27) | $ 58 | $ 8 | $ (22) | $ (14) | $ (54) | $ (34) | $ (88) |

A reconciliation of the federal statutory income tax rate applied to income (loss) before income taxes to the provision (benefit) for income taxes follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | **2021** | **2020** | **2019** |
| Total pre-tax income (loss) | $ 1,004 | $ (1,465) | $ 392 |
| Total income tax provision (benefit) | $ 58 | $ (14) | $ (88) |
| Effective income tax rate | 6 % | 1 % | (22)% |
| | | | |
| Income taxes at the statutory tax rate | $ 211 | $ (308) | $ 83 |
| Effects of foreign operations | (13) | 23 | (29) |
| Adjustments to valuation allowances | (166) | 239 | (28) |
| State income taxes, net of federal benefit | 23 | 6 | 11 |
| Tax law change | (2) | — | — |
| Other federal tax effects | 5 | 26 | (125) |
| Income tax provision (benefit) | $ 58 | $ (14) | $ (88) |

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income and the relative magnitude of these sources of income. The difference between the total provision and the sum of the amounts allocated to segments is reported in the “Not Allocated to Segments” column of the tables in **Note 5**.

*Effects of foreign operations* – The effects of foreign operations decreased our tax provision in 2021 largely due to the income mix within E.G. between equity method investees and subsidiaries which can reduce the effective tax rate below the U.S. statutory tax rate. The effects of foreign operations increased our tax provision in 2020 largely due to book losses in foreign jurisdictions with no corresponding tax benefits. The effects of foreign operations decreased our tax provision in 2019 due to tax benefits related to our U.K. operations and pre-tax income in jurisdictions with effective tax rates lower than the U.S.

*Adjustments to valuation allowances* – Since December 31, 2016, we have maintained a full valuation allowance on our net federal deferred tax assets. In all years, the most significant driver for the change in valuation allowance was due to current year activity in the U.S. We intend to continue a full valuation allowance on these deferred tax assets until there is sufficient evidence to support the reversal of all or some portion of the allowance. However, if current commodity prices are sustained and absent any additional objective negative evidence, we expect it is reasonably possible that sufficient positive evidence will exist within the next 12 months to adjust our current valuation allowance position. Exact timing and amount of the adjustment to the valuation allowance is unknown as this time.

*Other federal tax effects* – In 2020, the increase to other federal tax effects is largely related to non-deductible goodwill impairment. The 2019 decrease in other federal tax effects is primarily related to the settlement of the 2010-2011 U.S. Federal Tax Audit (“IRS Audit”) in the first quarter of 2019. The release of the accrued tax positions resulted in a $126 million tax benefit, primarily related to AMT credits.

Deferred tax assets and liabilities resulted from the following:

| | Year Ended December 31, | |
|---|---|---|
| *(In millions)* | **2021** | **2020** |
| Deferred tax assets: | | |
| Employee benefits | $ 66 | $ 77 |
| Operating loss carryforwards | 1,541 | 1,966 |
| Foreign tax credits | 611 | 611 |
| Other[(a)] | 52 | 67 |
| Subtotal | 2,270 | 2,721 |
| Valuation allowance | (780) | (948) |
| Total deferred tax assets | 1,490 | 1,773 |
| Deferred tax liabilities: | | |
| Property, plant and equipment[(a)] | 1,544 | 1,879 |
| Accrued revenue | — | 20 |
| Other[(a)] | 82 | 37 |
| Total deferred tax liabilities | 1,626 | 1,936 |
| Net deferred tax liabilities | $ 136 | $ 163 |
| Net deferred tax assets | $ — | $ — |

(a) 2020 balances were reclassified to conform to current period's presentation. The total Net deferred tax liabilities balance was not impacted by the change in presentation.

*Operating loss carryforwards* – At December 31, 2021, we have a gross deferred tax asset related to our operating loss carryforwards of $1.5 billion, before valuation allowance. U.S. operating loss carryforwards relating to tax years beginning prior to January 1, 2018, include $1.4 billion ($295 million deferred tax asset) that expire in 2036 - 2037. U.S. operating loss carryforwards for tax years beginning after December 31, 2017, include $5.3 billion ($1.1 billion deferred tax asset) which can be carried forward indefinitely. Foreign operating loss carryforwards include $26 million that expire in 2022 - 2027. State operating loss carryforwards of $3.3 billion ($125 million deferred tax asset) expire in 2022 through 2040.

*Foreign tax credits* – At December 31, 2021, we reflect foreign tax credits of $611 million, which will expire in years 2022 through 2026.

*Valuation allowances* – At December 31, 2021, we reflect a valuation allowance in our consolidated balance sheet of $780 million against our net deferred tax assets in various jurisdictions in which we operate. The decrease in valuation allowance primarily relates to current year activity in the U.S.

*Property, plant and equipment* – At December 31, 2021, we reflected a deferred tax liability of $1.5 billion. The decrease primarily relates to current year activity in the U.S.

Net deferred tax assets and liabilities were classified in the consolidated balance sheets as follows:

| | December 31, | |
|---|---|---|
| *(In millions)* | **2021** | **2020** |
| Assets: | | |
| Other noncurrent assets | $ — | $ — |
| Liabilities: | | |
| Noncurrent deferred tax liabilities | 136 | 163 |
| Net deferred tax liabilities | $ 136 | $ 163 |
| Net deferred tax assets | $ — | $ — |

We are routinely undergoing examinations in the jurisdictions in which we operate. As of December 31, 2021, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

| | |
|---|---|
| United States[(a)] | 2010 - 2020 |
| Equatorial Guinea | 2007 - 2020 |

(a) Includes federal and state jurisdictions.

The following table summarizes the activity in unrecognized tax benefits:

| *(In millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| Beginning balance | $ 8 | $ 13 | $ 263 |
| Additions for tax positions of prior years | 2 | — | 13 |
| Reductions for tax positions of prior years | — | (5) | (152) |
| Settlements | — | — | (111) |
| Ending balance | $ 10 | $ 8 | $ 13 |

If the unrecognized tax benefits as of December 31, 2021 were recognized, $10 million would affect our effective income tax rate. As of December 31, 2021, we do not expect uncertain tax positions to significantly change within the next twelve months. During the first quarter of 2019, we withdrew our appeal related to the Brae area decommissioning costs in the U.K., thus the uncertain tax positions previously established are now considered effectively settled with no tax provision or benefit impact. Also, in the first quarter of 2019, we settled the 2010-2011 IRS Audit, resulting in a tax benefit of $126 million.

Interest and penalties are recorded as part of the tax provision and were immaterial for 2021, a $2 million tax benefit in 2020 and a $6 million tax provision in 2019. As of December 31, 2021 and 2020, we had no significant accrued interest or penalties related to income taxes. For December 31, 2019, $3 million of interest and penalties were accrued related to income taxes.

In the third quarter of 2020, we received an $89 million cash refund related to alternative minimum tax credits and interest. This refund was accelerated as a result of the enactment of the Coronavirus Aid, Relief, and Economic Security Act, commonly referred to as the CARES Act, in the first quarter of 2020.

## 9. Credit Losses

The majority of our receivables are from purchasers of commodities or joint interest owners in properties we operate, both of which are recorded at estimated or invoiced amounts and do not bear interest. The majority of these receivables have payment terms of 30 days or less. At the end of each reporting period, we assess the collectability of our receivables and estimate the expected credit losses using historical data, current market conditions and reasonable and supportable forecasts of future economic conditions and other data as deemed appropriate.

We are exposed to credit losses through the receivables generated from sales of crude oil, NGLs and natural gas to our customers. When dealing with the commodity purchasers, we conduct a credit review to assess each counterparty's ability to pay. The credit review considers our expected billing exposure, timing for payment and the counterparty's established credit rating with the rating agencies or our internal assessment of the counterparty's creditworthiness based on our analysis of their financial statements. Our evaluation also considers contract terms and other factors, such as country and/or political risk. A credit limit is established for each counterparty based on the outcome of this review. We may require a bank letter of credit or a prepayment to mitigate credit risk. We monitor our ongoing credit exposure through active review of counterparty balances against contract terms and due dates. The expected credit losses related to receivables with the commodity purchasers were determined using the weighted average probability of default method. We also collect revenues from our non-operated joint properties where other oil and gas exploration and production companies operate the properties and market our share of production and remit payments to us. The current expected credit losses related to these receivables were determined using the loss rate method applied to aging pools.

We are exposed to credit losses from joint interest billings to other joint interest owners for properties we operate. For this group of receivables, the expected credit losses are determined using the loss rate method applied to aging pools. Our counterparties in this group include numerous large, mid-size and small oil and gas exploration and production companies. Although we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings or require a prepayment of future costs through cash calls, our credit loss exposure with this group is more significant due to inherent ownership or billing adjustments. Also, some of our counterparties may experience liquidity problems and may not be able to meet their financial obligations to us.

Changes in the reserve for credit losses balance for the year were as follows:

| | December 31, | |
|---|---|---|
| *(In millions)* | **2021** | **2020** |
| Beginning balance as of January 1 | $ 22 | $ 11 |
| Cumulative-effect adjustment | — | 12 |
| Current period provision[(a)] | 3 | 22 |
| Current period write offs | (5) | (13) |
| Recoveries of amounts previously reserved | (5) | (10) |
| Ending balance as of December 31 | $ 15 | $ 22 |

(a) As of December 31, 2020, the current period provision consisted of $10 million in joint interest receivables and $12 million in trade receivables.

## 10. Inventories

Crude oil and natural gas are recorded at weighted average cost and carried at the lower of cost or net realizable value. Supplies and other items consist principally of tubular goods and equipment which are valued at weighted average cost and reviewed periodically for obsolescence or impairment when market conditions indicate.

| | December 31, | |
|---|---|---|
| *(In millions)* | **2021** | **2020** |
| Crude oil and natural gas | $ 8 | $ 10 |
| Supplies and other items | 69 | 66 |
| Inventories | $ 77 | $ 76 |

## 11. Property, Plant and Equipment

| | December 31, | |
|---|---|---|
| *(In millions)* | **2021** | **2020** |
| United States | $ 14,097 | $ 15,156 |
| International | 347 | 414 |
| Not allocated to segments | 55 | 68 |
| Net property, plant and equipment | $ 14,499 | $ 15,638 |

Changes in our capitalized exploratory well costs were as follows:

| | December 31, | | |
|---|---|---|---|
| *(In millions)* | **2021** | **2020** | **2019** |
| Beginning balance as of January 1 | $ 210 | $ 278 | $ 297 |
| Additions | 50 | 97 | 218 |
| Charges to expense | (30) | (1) | (5) |
| Transfers to development | (68) | (164) | (230) |
| Dispositions | — | — | (2) |
| Ending balance as of December 31 | $ 162 | $ 210 | $ 278 |

As of December 31, 2021 and 2020, we had $80 million and $98 million, respectively, of exploratory well costs capitalized greater than one year related to suspended wells. Management believes these wells exhibit sufficient quantities of hydrocarbons to justify potential development. The vast majority of the suspended wells require completion activities and installation of infrastructure in order to classify the reserves as proved. Of the $80 million as of December 31, 2021, approximately $40 million pertains to 2020, $34 million to 2019, and the remaining $6 million attributable to 2018 activities.

During the year ended December 31, 2021, we recorded $28 million of expense associated with drilled and uncompleted exploratory wells, primarily in the Permian, due to a change in our plan of development.

## 12. Impairments

The following table summarizes impairment charges of proved properties, goodwill and equity method investments and their corresponding fair values.

| | 2021 | | 2020 | | 2019 | |
|---|---|---|---|---|---|---|
| *(In millions)* | **Fair Value** | **Impairment** | **Fair Value** | **Impairment** | **Fair Value** | **Impairment** |
| Long-lived assets held for use | $ — | $ 30 | $ — | $ 49 | $ 56 | $ 24 |
| Asset retirement costs of long-lived assets | — | 30 | — | — | — | — |
| Goodwill | — | — | — | 95 | — | — |
| Equity method investment | $ — | $ — | $ 119 | $ 171 | $ — | $ — |

- **2021** – During the second quarter of 2021, we recorded an impairment expense of $24 million associated with two central facilities located in Eagle Ford. Decommissioning activities associated with these central facilities included the re-routing of existing wells. During the third quarter of 2021, we recorded an impairment expense of $5 million associated with our interests in outside operated conventional assets located in New Mexico.

  During the year ended December 31, 2021, we also recognized an incremental $30 million of impairment expense associated with an increase in the estimated future decommissioning costs of certain non-producing wells, pipelines and production facilities for previously divested offshore assets located in the Gulf of Mexico. In a prior reporting period, we recorded a $7 million liability in our consolidated balance sheet associated with these assets. Thus, the incremental expense in 2021 increased the total recognized asset retirement obligation to $37 million as of December 31, 2021. See **Note 13** and **Note 26** for further information.

  The combined effects of these items were recorded within the Impairments line item within our consolidated statements of income.

- **2020** – Impairments totaling $49 million of long-lived assets held for use resulted from a damaged, unsalvageable well and related equipment in the Louisiana Austin Chalk. The related fair value was measured based on the salvage value which resulted in a Level 3 classification.

  We impaired the entire balance of our goodwill in the International reporting unit totaling $95 million of goodwill. See **Note 15** for further information.

  Impairments also include charges recognized for our equity method investments of $171 million. During the second and third quarters of 2020, the continuation of the depressed commodity prices, along with a reduction of our long-term price forecasts of a gas index in which one of our equity method investees transacts, caused us to perform a review of one of our equity method investments. Our review concluded that a loss of our investment value in one was other than temporary and we recorded an impairment. Our remaining investments in equity method investees did not experience losses in value that caused the fair values to be below their carrying values.

  We estimated the fair value of our equity method investment using an income approach, specifically utilizing a discounted cash flow analysis. The estimated fair value was based on significant inputs not observable in the market, such as the amount of gas processed by the plant, future commodity prices, forecasted operating expenses, discount rate and estimated cash returned to shareholders. Collectively, these inputs represent Level 3 measurements.

  The impairments of our equity method investments were recognized in income (loss) from equity method investments in our consolidated statements of income. The impairments caused us to incur a basis differential between the net book value of our investment and the amount of our underlying share of equity in the investee's net assets. The amount of this basis differential was $140 million and is being accreted into income over the remaining useful life of the investee's primary assets.

  Finally, we impaired $78 million of unproved property leases in Louisiana Austin Chalk in our United States segment, which was recognized in exploration expense in our consolidated statements of income. The impairment resulted from a combination of factors including our geological assessment, seismic information, timing of lease expiration dates and decisions not to develop acreage deemed non-core. Collectively, these inputs represent Level 3 measurements.

- **2019** – Impairments of $24 million, to an aggregate fair value of $56 million, were primarily a result of anticipated sales for certain non-core proved properties in our United States segment and the sale of our non-operated interest in the Atrush block (Kurdistan) in our International segment. The related fair value was measured using the market approach, based upon anticipated sales proceeds less costs to sell which resulted in a Level 2 classification.

See **Note 5** for discussion of the divestitures in further detail and **Note 7** for relevant detail regarding segment presentation.

## 13. Asset Retirement Obligations

Asset retirement obligations primarily consist of estimated costs to remove, dismantle and restore land or seabed at the end of oil and gas production operations. Changes in asset retirement obligations were as follows:

| | December 31, | |
|---|---|---|
| *(In millions)* | **2021** | **2020** |
| Beginning balance as of January 1 | $ 254 | $ 254 |
| Incurred liabilities, including acquisitions | 14 | 6 |
| Settled liabilities, including dispositions | (6) | (12) |
| Accretion expense (included in depreciation, depletion and amortization) | 12 | 12 |
| Revisions of estimates | 42 | (6) |
| Ending balance as of December 31 | $ 316 | $ 254 |
| Ending balance as of December 31, short-term | $ 28 | $ 13 |

During the year ended December 31, 2021, we had revisions of estimates totaling $37 million related to anticipated costs for decommissioning certain wells, pipelines and production facilities for previously divested offshore non-producing long-lived assets located in the Gulf of Mexico. As of December 31, 2021, $14 million of these Gulf of Mexico related revisions of estimates were classified as short-term. See **Note 26** for further information. Of the $37 million, approximately $30 million was recognized as impairment expense during the year ended December 31, 2021. See **Note 12** for further information.

## 14. Leases

***Lessee***

*Operating Leases*

We enter into various lease agreements to support our operations including drilling rigs, well fracturing equipment, compressors, buildings, aircraft, vessels, vehicles and miscellaneous field equipment. We primarily act as a lessee in these transactions and the majority of our existing leases are classified as either short-term or long-term operating leases.

The majority of the drilling rig agreements and all of fracturing equipment agreements are classified as short-term leases based on the noncancellable period for which we have the right to use the equipment and assessment of options present in each agreement. We also incur variable lease costs under these agreements primarily related to chemicals and sand used in fracturing operations or various additional on-demand equipment and labor. The lease costs associated with the drilling rigs and fracturing equipment are primarily capitalized as part of the well costs.

Our existing long-term leases are comprised of compressors, drilling rigs, vessels, vehicles and miscellaneous field equipment. Our lease agreements may require both fixed and variable payments; none of the variable payments are rate or index-based, therefore only fixed payments were considered for recognizing lease liabilities and right-of-use ('ROU') assets related to long-term leases. Also, based on our election not to separate the lease and nonlease components, fixed payments related to equipment, crew and other nonlease components are included in the initial measurement of lease liabilities and ROU assets for all asset classes, except for vessels. For vessels, the contractual consideration was allocated between lease and nonlease components based on estimates provided by service providers.

Our leased assets may be used in joint oil and gas operations with other working interest owners. We recognize lease liabilities and ROU assets only when we are the signatory to a contract as an operator of joint properties. Such lease liabilities and ROU assets are determined based on gross contractual obligations. As we use the leased assets for joint operations, we have the contractual right to recover the other working interest owners' share of lease costs. As a result, our lease costs are presented on a net basis, reduced for any costs recoverable from other working interest owners.

*Finance Leases*

In 2018, we signed an agreement with an owner/lessor to construct and lease a new build-to-suit office building in Houston, Texas. As of December 31, 2021, project costs totaled approximately $302 million, including land acquisition and construction costs. The initial lease term is five years and commenced in late September 2021 after the new Houston office was ready for occupancy. In the third quarter of 2021, we recorded a $32 million ROU asset and corresponding lease liability associated with the building, which was classified as a finance lease. At the end of the initial lease term, we can negotiate to extend the lease term for an additional five years, subject to the approval of the participants; purchase the property subject to certain terms and conditions; or remarket the property to an unrelated third party. The lease contains a residual value guarantee of 100% of the total acquisition and construction costs.

*Balance Sheet Information*

Balance sheet information related to ROU assets and lease liabilities was as follows:

| *(In millions)* | | December 31, 2021 | December 31, 2020 |
|---|---|---|---|
| **ROU assets:** | **Balance Sheet Location:** | | |
| Operating leases | Other noncurrent assets | $ 59 | $ 133 |
| Finance leases | Other noncurrent assets | 28 | — |
| Total ROU assets | | $ 87 | $ 133 |
| **Lease liabilities:** | | | |
| Current liabilities | | | |
| Operating leases | Other current liabilities | $ 40 | $ 70 |
| Finance leases | Other current liabilities | 6 | — |
| Noncurrent liabilities | | | |
| Operating leases | Deferred credits and other liabilities | 23 | 67 |
| Finance leases | Deferred credits and other liabilities | 24 | — |
| Total lease liabilities | | $ 93 | $ 137 |

*Statements of Income Information*

The table below presents our net lease costs for the years ended December 31, 2021 and 2020.

| *(In millions)* | Year Ended December 31, 2021 | Year Ended December 31, 2020 |
|---|---|---|
| **Operating lease costs:** | | |
| Short-term lease costs[(a)] | $ 121 | $ 170 |
| Long-term lease costs[(b)] | 64 | 75 |
| Variable lease costs[(c)] | 33 | 23 |
| **Finance lease costs:** | | |
| Amortization of ROU assets | 3 | — |
| Total lease costs | $ 221 | $ 268 |
| | | |
| **Other information:** | | |
| Cash paid for amounts included in the measurement of operating lease liabilities | $ 73 | $ 100 |
| ROU assets obtained in exchange for new operating lease liabilities[(d)] | 15 | 46 |
| ROU assets obtained in exchange for new finance lease liabilities[(e)] | 28 | — |
| Reductions to ROU assets resulting from modifications or cancellations of operating leases | $ (13) | $ (68) |

(a) Represents our net share of lease costs arising from leases of less than one year but longer than one month that were not included in the lease liability.
(b) Represents our net share of the ROU asset amortization and the interest expense.
(c) Represents our net share of variable lease payments that were not included in the lease liability.
(d) Represents the cumulative value of operating lease ROU assets recognized at lease inception. This amount is then amortized as we utilize the ROU asset, the net effect of which is the ending ROU asset (first table above).
(e) Represents the cumulative value of finance lease ROU assets recognized at lease inception during the year of 2021. This amount is then amortized as we utilize the ROU asset, the net effect of which is the ending ROU asset of $28 million (first table above).

*Annual Lease Maturities*

The remaining annual undiscounted cash flows associated with long-term leases and the reconciliation of these cash flows to the lease liabilities recognized on the consolidated balance sheet is summarized below.

| *(In millions)* | Operating Lease Obligations | Finance Lease Obligations | Total Lease Obligations |
|---|---|---|---|
| 2022 | $ 45 | $ 7 | $ 52 |
| 2023 | 8 | 7 | 15 |
| 2024 | 5 | 7 | 12 |
| 2025 | 4 | 7 | 11 |
| 2026 | 2 | 4 | 6 |
| Thereafter | — | — | — |
| Total undiscounted lease payments | $ 64 | $ 32 | $ 96 |
| Less: amount representing interest | 1 | 2 | 3 |
| Total lease liabilities | $ 63 | $ 30 | $ 93 |
| Less: current portion of lease liability as of December 31, 2021 | 40 | 6 | 46 |
| Long-term lease liability as of December 31, 2021 | $ 23 | $ 24 | $ 47 |

*Other Information*

We use our periodic incremental borrowing rate to discount future contractual payments to their present values. For our operating leases, the weighted average lease term is two years and the discount rate is 3% as of December 31, 2021. For our finance leases, the weighted-average remaining lease term is five years and the discount rate is 2% as of December 31, 2021.

***Lessor***

Our wholly owned subsidiary, Marathon E.G. Production Limited, is a lessor for residential housing in Equatorial Guinea, which is occupied by EGHoldings, a related party equity method investee – see **Note 24**. The lease was classified as an operating lease and expires in 2024, with a lessee option to extend through 2034. Lease payments are fixed for the entire duration of the agreement at approximately $6 million per year. Our lease income is reported in other income in our consolidated statements of income for all periods presented. The undiscounted cash flows to be received under this lease agreement are summarized below.

| *(In millions)* | Operating Lease Future Cash Receipts |
|---|---|
| 2022 | $ 6 |
| 2023 | 6 |
| 2024 | 6 |
| 2025 | 6 |
| 2026 | 6 |
| Thereafter | 49 |
| Total undiscounted cash flows | $ 79 |

## 15. Goodwill

Goodwill is tested for impairment on an annual basis, or between annual tests when events or changes in circumstances indicate the fair value may have been reduced below its carrying value. During the first quarter of 2020, a global pandemic caused a substantial deterioration in the worldwide demand of hydrocarbons. The commensurate decline in our market capitalization during the first quarter indicated that it was more likely than not that the fair value of the International reporting unit was less than its carrying value.

We estimated the fair value of our International reporting unit using a combination of market and income approaches. The market approach referenced observable inputs specific to us and our industry, such as the price of our common equity, our enterprise value and valuation multiples of us and peers from the investor analyst community. The income approach utilized discounted cash flows, which were based on forecasted assumptions. These valuation methodologies represent Level 3 fair value measurements. Based on the results, we concluded our goodwill was fully impaired, and recorded an impairment of $95 million in the consolidated statements of income for the first quarter of 2020. This represented the entirety of our goodwill on our consolidated balance sheet.

### 16. Derivatives

See **Note 17** for further information regarding the fair value measurement of derivative instruments. See **Note 1** for discussion of the types of derivatives we may use and the reasons for them. All of our commodity derivatives and interest rate derivatives are/were subject to enforceable master netting arrangements or similar agreements under which we report net amounts. The following tables present the gross fair values of our open derivative instruments and the reported net amounts along with where they appear on the consolidated balance sheets.

| | December 31, 2021 | | | |
|---|---|---|---|---|
| *(In millions)* | **Asset** | **Liability** | **Net Asset (Liability)** | **Balance Sheet Location** |
| **Not Designated as Hedges** | | | | |
| Commodity | $ 1 | $ 8 | $ (7) | Other current liabilities |
| Interest Rate | 27 | — | 27 | Other noncurrent assets |
| Total Not Designated as Hedges | $ 28 | $ 8 | $ 20 | |
| **Cash Flow Hedges** | | | | |
| Interest Rate | $ — | $ 3 | $ (3) | Other current liabilities |
| Interest Rate | — | 2 | (2) | Deferred credits and other liabilities |
| Total Designated Hedges | $ — | $ 5 | $ (5) | |
| Total | $ 28 | $ 13 | $ 15 | |

| | December 31, 2020 | | | |
|---|---|---|---|---|
| *(In millions)* | **Asset** | **Liability** | **Net Asset (Liability)** | **Balance Sheet Location** |
| **Not Designated as Hedges** | | | | |
| Commodity | $ 3 | $ 1 | $ 2 | Other current assets |
| Commodity | 7 | 32 | (25) | Other current liabilities |
| Interest Rate | 10 | — | 10 | Other noncurrent assets |
| Total Not Designated as Hedges | $ 20 | $ 33 | $ (13) | |
| **Cash Flow Hedges** | | | | |
| Interest Rate | $ 19 | $ — | $ 19 | Other noncurrent assets |
| Interest Rate | — | 16 | (16) | Deferred credits and other liabilities |
| Total Designated Hedges | $ 19 | $ 16 | $ 3 | |
| Total | $ 39 | $ 49 | $ (10) | |

***Derivatives Not Designated as Hedges***

*Commodity Derivatives*

We have entered into multiple crude oil and natural gas derivatives indexed to the respective indices as noted in the table below, related to a portion of our forecasted United States sales through 2022. These derivatives consist of three-way collars and NYMEX roll basis swaps. Three-way collars consist of a sold call (ceiling), a purchased put (floor) and a sold put. The ceiling price is the maximum we will receive for the contract volumes; the floor is the minimum price we will receive, unless the market price falls below the sold put strike price. In this case, we receive the NYMEX WTI price plus the difference between the floor and the sold put price. Two-way collars only consist of a sold call (ceiling) and a purchased put (floor). These crude oil and natural gas derivatives were not designated as hedges.

The following table sets forth outstanding derivative contracts as of December 31, 2021 and the weighted average prices for those contracts:

| | 2022 | | | |
|---|---|---|---|---|
| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
| ***Crude Oil*** | | | | |
| ***NYMEX WTI Three-Way Collars*** | | | | |
| Volume (Bbls/day) | 50,000 | 50,000 | 20,000 | 20,000 |
| Weighted average price per Bbl: | | | | |
| Ceiling | $ 92.26 | $ 92.26 | $ 92.80 | $ 92.80 |
| Floor | $ 52.00 | $ 52.00 | $ 50.00 | $ 50.00 |
| Sold put | $ 42.00 | $ 42.00 | $ 40.00 | $ 40.00 |
| ***NYMEX Roll Basis Swaps*** | | | | |
| Volume (Bbls/day) | 45,000 | 45,000 | 45,000 | 45,000 |
| Weighted average price per Bbl | $ 0.56 | $ 0.56 | $ 0.56 | $ 0.56 |
| ***Natural Gas*** | | | | |
| ***Henry Hub ("HH") Three-Way Collars*** | | | | |
| Volume (MMBtu/day) | 50,000 | — | — | — |
| Weighted average price per MMBtu: | | | | |
| Ceiling | $ 5.14 | $ — | $ — | $ — |
| Floor | $ 3.60 | $ — | $ — | $ — |
| Sold Put | $ 2.60 | $ — | $ — | $ — |

The following table sets forth our outstanding derivative contracts as of February 14, 2022, with their weighted average prices, and is inclusive of activity that occurred subsequent to December 31, 2021.

| | 2022 | | | |
|---|---|---|---|---|
| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
| ***Crude Oil*** | | | | |
| ***NYMEX WTI Three-Way Collars*** | | | | |
| Volume (Bbls/day) | 50,000 | 50,000 | 50,000 | 50,000 |
| Weighted average price per Bbl: | | | | |
| Ceiling | $ 96.54 | $ 98.79 | $ 97.52 | $ 97.52 |
| Floor | $ 55.93 | $ 58.00 | $ 56.67 | $ 56.67 |
| Sold put | $ 45.93 | $ 48.00 | $ 46.67 | $ 46.67 |
| ***NYMEX Roll Basis Swaps*** | | | | |
| Volume (Bbls/day) | 50,167 | 60,000 | 60,000 | 60,000 |
| Weighted average price per Bbl | $ 0.60 | $ 0.67 | $ 0.67 | $ 0.67 |
| ***Natural Gas*** | | | | |
| ***HH Three-Way Collars*** | | | | |
| Volume (MMBtu/day) | 50,000 | 50,000 | 50,000 | 50,000 |
| Weighted average price per MMBtu: | | | | |
| Ceiling | $ 5.14 | $ 6.18 | $ 6.18 | $ 6.18 |
| Floor | $ 3.60 | $ 3.50 | $ 3.50 | $ 3.50 |
| Sold put | $ 2.60 | $ 2.50 | $ 2.50 | $ 2.50 |

The unrealized and realized gain (loss) impact of our commodity derivative instruments appears in the table below and is reflected in net gain (loss) on commodity derivatives in the consolidated statements of income.

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | 2021 | 2020 | 2019 |
| Unrealized gain (loss) on derivative instruments, net | $ 16 | $ (27) | $ (124) |
| Realized gain (loss) on derivative instruments, net[a] | $ (399) | $ 143 | $ 52 |

[a] During the year ended 2021, net cash paid for settled derivative positions was $356 million. During the years ended 2020 and 2019, net cash received for settled derivative positions was $123 million and $65 million, respectively.

*Interest Rate Swaps*

During 2020, we entered into forward starting interest rate swaps with a notional amount of $500 million to hedge the variations in cash flows as a result of fluctuations in the London Interbank Offered Rate ("LIBOR") benchmark interest rate related to forecasted interest payments of a future debt issuance in 2022. Each respective derivative contract was associated with an anticipated underlying dollar notional amount. During the third quarter of 2020, we de-designated these forward starting interest rate swaps previously designated as cash flow hedges. In the first quarter of 2021, the net deferred loss of $2 million in accumulated other comprehensive income related to these hedges was reclassified from accumulated other comprehensive income into earnings as an adjustment to net interest, as we fully redeemed the remainder of our outstanding 2022 notes in April 2021. See **Note 18** for further details about the debt redemption. In November 2021, we closed the positions and settled the interest rate swaps. During the twelve months ended December 31, 2021, our cumulative gains recorded within net interest totaled $28 million for these swaps.

During 2020, we entered into forward starting interest rate swaps with a notional amount of $350 million to hedge variations in cash flows arising from fluctuations in the LIBOR benchmark interest rate related to forecasted interest payments of a future debt issuance in 2025. The expected proceeds of the future debt issuance were intended to refinance the $900 million 3.85% Senior Notes due 2025 ("2025 Notes"). During the second quarter of 2021, we de-designated these forward interest rate swaps previously designated as cash flow hedges because we no longer planned to refinance the 2025 Notes. In the second quarter of 2021, we reclassified the $31 million cumulative gain related to these hedges from accumulated other comprehensive income into earnings as an adjustment to net interest. In September 2021, we fully redeemed these 2025 Notes. See **Note 18** for further details about the debt redemption. These positions remain open. Subsequent to the de-designation, we recorded additional mark-to-market losses totaling $4 million. Thus, for the twelve months ended December 31, 2021, the total amount recorded within net interest related to these swaps was $27 million.

During the second quarter of 2021, we de-designated $25 million of the $320 million Houston office cash flow hedges (discussed further in the *Derivatives Designated as Cash Flow Hedges* section below), as the construction cost budget estimate was reduced. The $1 million loss of these de-designated cash flow hedges as of June 30, 2021 was reclassified from accumulated other comprehensive income into earnings as an adjustment to net interest. The mark-to-market activity within net interest to reflect the change in value of these interest rate swaps during the year ended December 31, 2021 was immaterial.

The following table presents, by maturity date, information about our de-designated forward starting interest rate swap agreements, including the rate. We have the discretion to liquidate the positions should we choose.

| | December 31, 2021 | | December 31, 2020 | |
|---|---|---|---|---|
| **Maturity Date** | **Aggregate Notional Amount** *(in millions)* | **Weighted Average, LIBOR** | **Aggregate Notional Amount** *(in millions)* | **Weighted Average, LIBOR** |
| November 1, 2022 | $ — | — % | $ 500 | 0.99 % |
| June 1, 2025 | $ 350 | 0.95 % | N/A | N/A |
| September 9, 2026 | $ 25 | 1.45 % | N/A | N/A |

***Derivatives Designated as Cash Flow Hedges***

During 2019, we entered into forward starting interest rate swaps with a total notional amount of $320 million to hedge variations in cash flows related to the 1-month LIBOR component of future lease payments of our future Houston office. Although lease commencement began in September 2021, we expect our first cash lease payment will be in February 2022 and the first settlement date for the interest rate swap will be in January 2022. During the second quarter of 2021, we de-designated $25 million of these hedges as the construction cost budget estimate associated with the project was reduced. The last swap will mature in September 2026. As of December 31, 2021, we expect to reclassify $3 million loss from accumulated other comprehensive income into the income statement over the next twelve months. See **Note 14** for further details regarding the lease of the new Houston office.

The following table presents information about our interest rate swap agreements, including the weighted average LIBOR-based, fixed rate.

| | December 31, 2021 | | December 31, 2020 | |
|---|---|---|---|---|
| Maturity Date | Aggregate Notional Amount *(in millions)* | Weighted Average, LIBOR | Aggregate Notional Amount *(in millions)* | Weighted Average, LIBOR |
| June 1, 2025 | N/A | N/A | $ 350 | 0.95 % |
| September 9, 2026 | $ 295 | 1.52 % | $ 320 | 1.51 % |

## 17. Fair Value Measurements

*Fair Values – Recurring*

The following tables present assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2021 and 2020 by hierarchy level.

| | December 31, 2021 | | | |
|---|---|---|---|---|
| *(In millions)* | Level 1 | Level 2 | Level 3 | Total |
| **Derivative instruments, assets** | | | | |
| Interest rate - not designated as cash flow hedges | $ — | $ 27 | $ — | $ 27 |
| Derivative instruments, assets | $ — | $ 27 | $ — | $ 27 |
| **Derivative instruments, liabilities** | | | | |
| Commodity[(a)] | $ (2) | $ (5) | $ — | $ (7) |
| Interest rate - designated as cash flow hedges | — | (5) | — | (5) |
| Derivative instruments, liabilities | $ (2) | $ (10) | $ — | $ (12) |
| Total | $ (2) | $ 17 | $ — | $ 15 |

| | December 31, 2020 | | | |
|---|---|---|---|---|
| *(In millions)* | Level 1 | Level 2 | Level 3 | Total |
| **Derivative instruments, assets** | | | | |
| Interest rate - not designated as cash flow hedges | $ — | 10 | $ — | $ 10 |
| Interest rate - designated as cash flow hedges | — | 19 | — | 19 |
| Derivative instruments, assets | $ — | $ 29 | $ — | $ 29 |
| **Derivative instruments, liabilities** | | | | |
| Commodity[(a)] | $ — | $ (23) | $ — | $ (23) |
| Interest rate - designated as cash flow hedges | $ — | $ (16) | $ — | $ (16) |
| Derivative instruments, liabilities | $ — | $ (39) | $ — | $ (39) |
| Total | $ — | $ (10) | $ — | $ (10) |

(a) Derivative instruments are recorded on a net basis in our consolidated balance sheet (See **Note 16**).

As of December 31, 2021, our commodity derivatives include three-way collars and NYMEX roll basis swaps. These instruments are measured at fair value using either a Black-Scholes or a modified Black-Scholes Model. For swaps, inputs to the models include only commodity prices and interest rates and are categorized as Level 1 because all assumptions and inputs are observable in active markets throughout the term of the instruments. For three-way collars and two-way collars, inputs to the models include commodity prices, and implied volatility and are categorized as Level 2 because predominantly all assumptions and inputs are observable in active markets throughout the term of the instruments.

The forward starting interest rate swaps are measured at fair value with a market approach using actionable broker quotes, which are Level 2 inputs. See **Note 16** for details on the forward starting interest swaps.

*Fair Values – Goodwill*

See **Note 15** for detail information relating to goodwill.

*Fair Values – Nonrecurring*

See **Note 12** for detail on our fair values related to impairments.

*Fair Values – Financial Instruments*

Our current assets and liabilities include financial instruments, the most significant of which are receivables, the current portion of our long-term debt and payables. We believe the carrying values of our receivables and payables approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments, (2) our credit rating and (3) our historical incurrence of and expected future insignificance of bad debt expense, which includes an evaluation of counterparty credit risk.

The following table summarizes financial instruments, excluding receivables, payables and derivative financial instruments, and their reported fair values by individual balance sheet line item at December 31, 2021 and 2020.

| | December 31, | | | |
|---|---|---|---|---|
| | 2021 | | 2020 | |
| *(In millions)* | Fair Value | Carrying Amount | Fair Value | Carrying Amount |
| **Financial assets** | | | | |
| Current assets | $ 11 | $ 10 | $ 4 | $ 4 |
| Other noncurrent assets | 12 | 27 | 24 | 37 |
| Total financial assets | $ 23 | $ 37 | $ 28 | $ 41 |
| **Financial liabilities** | | | | |
| Other current liabilities | $ 99 | $ 136 | $ 72 | $ 103 |
| Long-term debt, including current portion[(a)] | 4,705 | 4,033 | 6,077 | 5,431 |
| Deferred credits and other liabilities | 46 | 46 | 82 | 76 |
| Total financial liabilities | $ 4,850 | $ 4,215 | $ 6,231 | $ 5,610 |

(a) Excludes debt issuance costs.

Fair values of our financial assets included in other noncurrent assets, and of our financial liabilities included in other current liabilities and deferred credits and other liabilities, are measured using an income approach and most inputs are internally generated, which results in a Level 3 classification. Estimated future cash flows are discounted using a rate deemed appropriate to obtain the fair value.

All of our long-term debt instruments are publicly traded. A market approach, based upon quotes from major financial institutions, which are Level 2 inputs, is used to measure the fair value of our debt.

## 18. Debt

*Revolving Credit Facility*

As of December 31, 2021, we had no borrowings against our $3.1 billion unsecured revolving credit facility ("Credit Facility").

On June 21, 2021, we executed the sixth amendment to our Credit Facility. The primary changes resulting from this amendment are (i) increasing the size of the Credit Facility from $3.0 billion to $3.1 billion, (ii) extending the maturity of the commitments of certain consenting lenders from May 28, 2023 to June 21, 2024 (with the remaining commitment of a single non-consenting lender to mature on May 28, 2023, at which time the size of the Credit Facility will be reduced to $3.0 billion) and (iii) including certain other provisions and revisions, including provisions to provide for the eventual replacement of LIBOR as a benchmark interest rate.

The Credit Facility includes a covenant requiring our total debt to total capitalization ratio not to exceed 65% as of the last day of each fiscal quarter. In the event of a default, the lenders holding more than half of the commitments may terminate the commitments under the Credit Facility and require the immediate repayment of all outstanding borrowings and the cash collateralization of all outstanding letters of credit under the Credit Facility. As of December 31, 2021, we were in compliance with this covenant with a ratio of 20%.

*Long-term debt*

The following table details our long-term debt:

| *(In millions)* | December 31, 2021 | December 31, 2020 |
|---|---|---|
| **Senior unsecured notes:** | | |
| 2.800% notes due 2022 | $ — | $ 500 |
| 9.375% notes due 2022[(a)] | 32 | 32 |
| Series A notes due 2022[(a)] | 3 | 3 |
| 8.500% notes due 2023[(a)] | 70 | 70 |
| 8.125% notes due 2023[(a)] | 131 | 131 |
| 3.850% notes due 2025 | — | 900 |
| 4.400% notes due 2027[(b)] | 1,000 | 1,000 |
| 6.800% notes due 2032[(b)] | 550 | 550 |
| 6.600% notes due 2037[(b)] | 750 | 750 |
| 5.200% notes due 2045[(b)] | 500 | 500 |
| **Bonds:**[(c)] | | |
| 2.00% bonds due 2037 | 200 | 200 |
| 2.10% bonds due 2037 | 200 | 200 |
| 2.20% bonds due 2037 | 200 | 200 |
| 2.125% bonds due 2037 | 200 | 200 |
| 2.375% bonds due 2037 | 200 | 200 |
| Total | 4,036 | 5,436 |
| Unamortized discount | (3) | (5) |
| Unamortized debt issuance cost | (19) | (27) |
| Total long-term debt | $ 4,014 | $ 5,404 |

(a) In the event of a change in control, as defined in the related agreements, debt obligations totaling $236 million at December 31, 2021 may be declared immediately due and payable

(b) These notes contain a make-whole provision allowing us to repay the debt at a premium to market price.

(c) Mandatory purchase dates for these bonds: April 1, 2023 for the 2.00% bonds; July 1, 2024 for the 2.10% bonds and 2.125% bonds; July 1, 2026 for the 2.20% bonds and 2.375% bonds. Subsequent to the various mandatory purchase dates, we will also have the right to convert and remarket these any time up to the 2037 maturity date.

The following table shows future debt payments:

| *(In millions)* | |
|---|---|
| 2022 | $ 35 |
| 2023 | 401 |
| 2024 | 400 |
| 2025 | — |
| 2026 | 400 |
| Thereafter | 2,800 |
| Total long-term debt, including current portion | $ 4,036 |

*Debt Redemption*

On March 30, 2021, we sent an irrevocable notice of redemption to the trustee to fully redeem our outstanding $500 million 2.8% Senior Notes due 2022 (“2022 Notes”). The 2022 Notes were redeemed on April 29, 2021 and as a result of the settlement, we incurred $19 million in costs related to a make-whole provision premium and the write off of unamortized discount and issuance costs.

On August 4, 2021, we sent an irrevocable notice of redemption to the trustee to fully redeem our outstanding $900 million 3.85% Senior Notes due 2025 ("2025 Notes"). The 2025 Notes were redeemed on September 7, 2021 and as a result of the redemption, we incurred $102 million in costs related to the make-whole provision premium and the write off of unamortized discount and issuance costs.

## 19. Incentive Based Compensation

***Description of stock-based compensation plans*** – The Marathon Oil Corporation 2019 Incentive Compensation Plan (the "2019 Plan") was approved by our stockholders in May 2019 and authorizes the Compensation Committee of the Board of Directors to grant stock options, stock appreciation rights ("SARs"), stock awards (including restricted stock and restricted stock unit awards), performance unit awards and cash awards to employees. The 2019 Plan also allows us to provide equity compensation to our non-employee directors. No more than 27.9 million shares of our common stock may be issued under the 2019 Plan. In connection with the granting of an award under the 2019 Plan, the number of shares available for issuance under the 2019 Plan will be reduced by one share for each share of our common stock in respect of which the award is granted, except the awards that by their terms do not permit settlement in shares of our common stock will not reduce the number of shares of common stock available for issuance under the 2019 Plan.

Shares subject to awards under the 2019 Plan that are forfeited, terminated or expire unexercised become available for future grants. In addition, the number of shares of our common stock reserved for issuance under the 2019 Plan will not be increased by shares tendered to satisfy the purchase price of an award, exchanged for other awards or withheld to satisfy tax withholding obligations. Shares issued as a result of awards granted under the 2019 Plan are generally funded out of common stock held in treasury, except to the extent there are insufficient treasury shares, in which case new common shares are issued.

After approval of the 2019 Plan, no new grants were or will be made from any prior plans. Any awards previously granted under any prior plans shall continue to be exercisable in accordance with their original terms and conditions.

***Stock-based awards under the plans***

*Stock options* – We last granted stock options under the 2019 Plan in 2020. Our stock options represent the right to purchase shares of our common stock at its fair market value on the date of grant. In general, our stock options vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

*SARs* – At December 31, 2021, there are no SARs outstanding.

*Restricted stock* – We last granted restricted stock under the 2019 Plan in 2020. The restricted stock awards granted to officers generally vest three years from the date of grant, contingent on the recipient's continued employment. We also grant restricted stock to certain non-officer employees based on their performance within certain guidelines and for retention purposes. The restricted stock awards to non-officers generally vest ratably over a three-year period, contingent on the recipient's continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares of restricted stock are not transferable and are held by our transfer agent.

*Stock-based performance unit awards* – We grant stock-based performance units to officers under the 2019 Plan.

During 2021, we granted 307,473 stock-based performance units to eligible officers, which are settled in shares. The grant date fair value per unit was $18.07, as calculated using a Monte Carlo valuation model. At the grant date, each unit represents the value of one share of our common stock. These units are settled in shares, and the number of shares of our common stock to be paid is based on the vesting percentage, which can be from zero to 200% based on performance achieved during the performance period and as determined by the Compensation Committee of the Board of Directors ("Compensation Committee"). The performance goals are tied to our total shareholder return ("TSR") as compared to TSR for a group, which is determined by the Compensation Committee and includes peer companies, the S&P Energy Index and the S&P 500 Index. Also, dividend equivalents accrue during the performance period and will be paid in cash following the end of the performance period based on the amount of dividends credited on shares of our common stock over the performance period multiplied by the number of units that vest.

During 2021, we introduced a new type of stock-based performance unit award under the 2019 Plan and granted 307,473 units to eligible officers, which are settled in cash. At the grant date for these new stock-based performance units, each unit represents the value of one share of our common stock. The benefit amount to be paid is based on the product of (i) the number of units granted, (ii) the vesting percentage and (iii) the average daily closing price of our common stock during the final 30 calendar days ending on the last trading day of the performance period, subject to the banking feature described below. The vesting percentage can range from zero to 200%, which is based on performance achieved over a two-year performance period. The performance metric is a predetermined amount of cumulative free cash flow, as defined by the award agreement, generated by the Company over the performance period. The units have a banking feature whereby the stock price valuation and vesting percentage are fixed at no less than 50%, and then again at 100%, if achieved during the performance period. Once those milestones are reached, the vesting percentage will not fall below those banked percentage amounts even if cumulative free cash flow subsequently declines during the performance period, subject to the Compensation Committee's discretion as described below. The fourth quarter 2021 fair value per unit was $15.55, as calculated by multiplying the estimated vesting percentage by our common stock's closing stock price on December 31, 2021. Also, dividend equivalents accrue during the performance period and would be paid in cash following the end of the performance period based on the amount of dividends credited on shares of our common stock over the performance period multiplied by the number of units that vest. The fourth quarter 2021 fair value of dividend equivalents per unit was $0.18. As set forth in the award agreement terms, the Compensation Committee retains discretion to reduce the vesting percentage and any bank values and determine free cash flow achievement for these awards.

*Restricted stock units* – We maintain an equity compensation program for our non-employee directors. All non-employee directors receive annual grants of common stock units. Any units granted prior to 2012 must be held until completion of board service, at which time the non-employee director will receive common shares. For units granted between 2012 and 2020, common shares will generally vest following completion of board service or three years from the date of grant, whichever is earlier. For units granted in 2021, common shares will generally vest following completion of board services or one year from the date of grant, whichever is earlier. However, for any units granted in 2017 or later, our non-employee directors may elect to defer settlement of their common stock units until after they cease serving on the Board. Under the 2019 Plan, we also grant restricted stock units to officers, which, depending on grant agreement terms, generally vest three years from the date of the grant or vest ratably over a three-year period and restricted stock units to certain non-officer employees, which generally vest ratably over a three-year period. Both awards are contingent on the recipient's continued employment. Grants of restricted stock units to these non-officer employees are generally based on their performance and for retention purposes. Common shares will be issued for these restricted stock units after vesting. Prior to vesting, recipients of restricted stock units typically receive dividend equivalent payments, but they may not vote.

***Total stock-based compensation expense*** – Total employee stock-based compensation expense was $43 million, $55 million and $60 million in 2021, 2020 and 2019. Due to the full valuation allowance on our net federal deferred tax assets, we recognized no tax benefit during these years. Cash received upon exercise of stock option awards was $5 million in 2021 and $1 million in both 2020 and 2019. There were no tax benefits recognized for deductions for stock awards settled during 2021, 2020 and 2019.

***Stock option awards*** – During 2020 and 2019 we granted stock option awards to officer employees. The weighted average grant date fair value of these awards was based on the following weighted average Black-Scholes assumptions:

| | 2020 | 2019 |
|---|---|---|
| Exercise price per share | $ 10.47 | $ 16.79 |
| Expected annual dividend yield | 1.9 % | 1.2 % |
| Expected life in years | 6.14 | 5.82 |
| Expected volatility | 44 % | 43 % |
| Risk-free interest rate | 1.5 % | 2.5 % |
| Weighted average grant date fair value of stock option awards granted | $ 3.82 | $ 6.62 |

The following is a summary of stock option award activity in 2021.

| | Number of Shares | Weighted Average Exercise Price | Weighted Average Remaining Contractual Term | Aggregate Intrinsic Value *(in millions)* |
|---|---|---|---|---|
| Outstanding at beginning of year | 6,014,255 | $ 21.00 | | |
| Granted | — | $ — | | |
| Exercised/Vested | (602,842) | $ 9.10 | | |
| Canceled | (1,137,109) | $ 23.10 | | |
| Outstanding at end of year | 4,274,304 | $ 22.13 | 5 years | $ 6,256,356 |
| Exercisable at end of year | 3,541,275 | $ 24.26 | 4 years | $ 2,816,507 |
| Expected to vest | 731,889 | $ 11.81 | 8 years | $ 3,433,157 |

The intrinsic value of stock option awards exercised was $3 million in 2021 and immaterial in both 2020 and 2019.

As of December 31, 2021, unrecognized compensation cost related to stock option awards was less than $1 million, almost all of which will be recognized in 2022.

***Restricted stock awards and restricted stock units*** – The following is a summary of restricted stock and restricted stock unit award activity in 2021.

| | Awards | Weighted Average Grant Date Fair Value |
|---|---|---|
| Unvested at beginning of year | 7,851,754 | $ 11.72 |
| Granted | 2,306,696 | $ 11.21 |
| Vested | (3,086,302) | $ 12.78 |
| Canceled | (1,183,906) | $ 11.62 |
| Unvested at end of year | 5,888,242 | $ 10.98 |

The vesting date fair value of restricted stock awards and restricted stock units which vested during 2021, 2020 and 2019 was $39 million, $49 million and $48 million. The weighted average grant date fair value of restricted stock awards was $10.98, $11.72 and $15.88 for awards unvested at December 31, 2021, 2020 and 2019.

As of December 31, 2021 there was $28 million of unrecognized compensation cost related to restricted stock awards and restricted stock units, which is expected to be recognized over a weighted average period of 1 year.

***Stock-based performance unit awards*** – During 2021, 2020 and 2019 we granted 307,473, 1,038,676 and 656,636 stock-based performance unit awards to be settled in shares to officers. At December 31, 2021, there were 1,622,994 units outstanding. During 2021, we also granted 307,473 stock-based performance unit awards to be settled in cash to officers. At December 31, 2021, there were 307,473 units outstanding. Total stock-based performance unit awards expense was $11 million, $5 million and $7 million in 2021, 2020 and 2019.

The key assumptions used in the Monte Carlo simulation to determine the grant date fair value of stock-based performance units granted in 2021, 2020 and 2019 were:

| | 2021 | 2020 | 2019 |
|---|---|---|---|
| Valuation date stock price | $ 11.20 | $ 10.47 | $ 16.79 |
| Expected annual dividend yield | 1.1 % | 1.9 % | 1.2 % |
| Expected volatility | 71 % | 39 % | 43 % |
| Risk-free interest rate | 0.3 % | 1.4 % | 2.5 % |
| Fair value of stock-based performance units outstanding | $ 18.07 | $ 10.55 | $ 20.66 |

## 20. Defined Benefit Postretirement Plans and Defined Contribution Plan

We have noncontributory defined benefit pension plans covering substantially all domestic employees. Benefits under these plans are based on plan provisions specific to each plan.

We also had a noncontributory defined benefit pension plan covering eligible U.K. employees that was transferred to the buyer in connection with the sale of our U.K. business during 2019. See **Note 5** for further information on this disposition. During the year ended December 31, 2019, we reclassified $20 million from accumulated other comprehensive income to pension assets upon remeasurement of the plan.

We also have plans for other postretirement benefits covering our U.S. employees. Health care benefits are provided up to age 65 through comprehensive hospital, surgical and major medical benefit provisions subject to various cost-sharing features. Post-65 retiree health care benefits have been provided to certain U.S. employees on a defined contribution basis; this program terminated effective as of December 31, 2020. Life insurance benefits are provided to certain retiree beneficiaries. These other postretirement benefits are not funded in advance. Employees hired after 2016 are not eligible for any postretirement health care or life insurance benefits.

*Obligations and funded status* – The following summarizes the obligations and funded status for our defined benefit pension and other postretirement plans.

| | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| | 2021 | 2020 | 2021 | 2020 |
| *(In millions)* | U.S. | U.S. | U.S. | U.S. |
| **Accumulated benefit obligation** | $ 260 | $ 298 | $ 73 | $ 80 |
| **Change in pension benefit obligations:** | | | | |
| Beginning balance | $ 308 | $ 354 | $ 80 | $ 89 |
| Service cost | 16 | 19 | — | 1 |
| Interest cost | 7 | 9 | 2 | 2 |
| Actuarial (gain) loss | (15) | 36 | 1 | 4 |
| Gain due to curtailment[(a)] | — | (1) | — | — |
| Settlements paid | (43) | (104) | — | — |
| Benefits paid | (4) | (5) | (10) | (16) |
| Ending balance | $ 269 | $ 308 | $ 73 | $ 80 |
| **Change in fair value of plan assets:** | | | | |
| Beginning balance | $ 194 | $ 236 | $ — | $ — |
| Actual return on plan assets | 13 | 18 | — | — |
| Employer contributions | 32 | 49 | 10 | 16 |
| Settlements paid | (43) | (104) | — | — |
| Benefits paid | (4) | (5) | (10) | (16) |
| Ending balance | $ 192 | $ 194 | $ — | $ — |
| **Funded status of plans at December 31** | $ (77) | $ (114) | $ (73) | $ (80) |
| **Amounts recognized in the consolidated balance sheets:** | | | | |
| Current liabilities | $ (3) | $ (4) | $ (10) | $ (10) |
| Noncurrent liabilities | (74) | (110) | (63) | (70) |
| Accrued benefit cost | $ (77) | $ (114) | $ (73) | $ (80) |
| **Pretax amounts in accumulated other comprehensive loss:** | | | | |
| Net loss | $ 37 | $ 72 | $ 23 | $ 24 |
| Prior service credit | (13) | (19) | (81) | (97) |

(a) Related to workforce reductions, which reduced the future expected years of service for employees participating in the plans.

In 2021, the pension plans experienced a net actuarial gain and the postretirement plans experienced a net actuarial loss. Both pension and postretirement plans experienced an increase in discount rate used to measure the plans, which decreased their respective benefit obligations and was the primary source of the actuarial gain for the pension plans. The postretirement plans experienced an overall net actuarial loss due to the mid-year census data update.

*Components of net periodic benefit costs and other comprehensive (income) loss* – The following summarizes the net periodic benefit costs and the amounts recognized as other comprehensive (income) loss for our defined benefit pension and other postretirement plans.

| | Pension Benefits | | | | Other Benefits | | |
|---|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | Year Ended December 31, | | |
| | 2021 | 2020 | 2019 | | 2021 | 2020 | 2019 |
| *(In millions)* | U.S. | U.S. | U.S. | Int'l | U.S. | U.S. | U.S. |
| **Components of net periodic benefit costs:** | | | | | | | |
| Service cost | $ 16 | $ 19 | $ 19 | $ — | $ — | $ 1 | $ 1 |
| Interest cost | 7 | 9 | 12 | 8 | 2 | 2 | 3 |
| Expected return on plan assets | (8) | (11) | (10) | (11) | — | — | — |
| **Amortization:** | | | | | | | |
| - prior service credit | (6) | (6) | (7) | — | (16) | (18) | (19) |
| - actuarial loss | 5 | 9 | 7 | — | 2 | 2 | 1 |
| Net settlement loss[(a)] | 9 | 30 | 12 | — | — | — | — |
| Net curtailment gain[(b)] | — | (3) | — | — | — | (14) | — |
| Net periodic benefit cost (credit) [(c)] | $ 23 | $ 47 | $ 33 | $ (3) | $ (12) | $ (27) | $ (14) |
| **Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):** | | | | | | | |
| Actuarial loss (gain) | $ (21) | $ 27 | $ 14 | $ (21) | $ 1 | $ 4 | $ 9 |
| Settlement loss and amortization of actuarial gain (loss) | (14) | (40) | (19) | (41) | (2) | (2) | (1) |
| Prior service cost (credit) | — | — | — | — | — | — | — |
| Curtailment gain and amortization of prior service credit (cost) | 6 | 10 | 7 | (6) | 16 | 32 | 19 |
| Total recognized in other comprehensive (income) loss | $ (29) | $ (3) | $ 2 | $ (68) | $ 15 | $ 34 | $ 27 |
| Total recognized in net periodic benefit cost and other comprehensive (income) loss | $ (6) | $ 44 | $ 35 | $ (71) | $ 3 | $ 7 | $ 13 |

(a) Settlements are recognized as they occur, once it is probable that lump sum payments from a plan for a given year will exceed the plan's total service and interest costs for that year.
(b) Related to workforce reductions, which reduced the future expected years of service for employees participating in the plans.
(c) Net periodic benefit costs (credits) reflects a calculated market-related value of plan assets, which recognizes changes in fair value over three years.

*Plan assumptions* – The following summarizes the assumptions used to determine the benefit obligations at December 31, and net periodic benefit cost for the defined benefit pension and other postretirement plans for 2021, 2020 and 2019.

| | Pension Benefits | | | Other Benefits | | |
|---|---|---|---|---|---|---|
| | 2021 | 2020 | 2019 | 2021 | 2020 | 2019 |
| *(In millions)* | U.S. | U.S. | U.S. | U.S. | U.S. | U.S. |
| **Weighted average assumptions used to determine benefit obligation:** | | | | | | |
| Discount rate | 2.83 % | 2.52 % | 3.13 % | 2.48 % | 2.02 % | 2.91 % |
| Rate of compensation increase[(a)] | 0.50 % | 0.50 % | 4.50 % | 0.50 % | 0.50 % | 4.50 % |
| Cash balance interest crediting | 3.00 % | 3.00 % | 3.00 % | — % | — % | — % |
| **Weighted average assumptions used to determine net periodic benefit cost:** | | | | | | |
| Discount rate | 2.77 % | 2.90 % | 3.70 % | 2.02 % | 2.63 % | 4.09 % |
| Expected long-term return on plan assets | 5.75 % | 6.00 % | 6.25 % | — % | — % | — % |
| Rate of compensation increase[(b)] | 0.50 % | 4.50 % | 4.00 % | 0.50 % | 4.50 % | 4.00 % |
| Cash balance interest crediting | 3.00 % | 3.00 % | 3.00 % | — % | — % | — % |

(a) The assumed rate of compensation increase is 5.00% for the year 2022 and 4.50% for future years.
(b) The assumed rate of compensation increase is 4.50% for future years.

*Expected long-term return on plan assets* – The expected long-term return on plan assets assumption for our U.S. pension plan is determined based on an internally developed asset rate-of-return modeling tool, which utilizes underlying assumptions based on actual returns by asset category and inflation and takes into account our U.S. pension plan's asset allocation. The expected return for each asset category is then weighted based on the actual asset allocation to develop the overall expected long-term return on plan assets assumption.

*Assumed weighted average health care cost trend rates* – Employer provided subsidies for post-65 retiree health care coverage were frozen effective January 1, 2017 at January 1, 2016 established amount levels. Company contributions were funded to a Health Reimbursement Account on the retiree's behalf to subsidize the retiree's cost of obtaining health care benefits through a private exchange (the "post-65 retiree health benefits").

In the fourth quarter of 2018, we terminated the post-65 retiree health benefits effective as of December 31, 2020. The post-65 retiree health benefits are no longer be provided after that date. In addition, the pre-65 retiree medical coverage subsidy was frozen as of January 1, 2019, and the ability for retirees to opt in and out of this coverage, as well as pre-65 retiree dental and vision coverage, was also eliminated. Retirees must enroll in connection with retirement for such coverage, or they lose eligibility. These plan changes reduced our retiree medical benefit obligation by approximately $99 million at December 31, 2018.

*Plan investment policies and strategies* – The investment policies for our U.S. pension plan assets reflect the funded status of the plan and expectations regarding our future ability to make further contributions. Long-term investment goals are to: (1) manage the assets in accordance with applicable legal requirements; (2) produce investment returns which meet or exceed the rates of return achievable in the capital markets while maintaining the risk parameters set by the plan's investment committees and protecting the assets from any erosion of purchasing power; and (3) position the portfolios with a long-term risk/return orientation. Investment performance and risk is measured and monitored on an ongoing basis through quarterly investment meetings and periodic asset and liability studies.

*U.S. plan* – The plan's current targeted asset allocation is comprised of 55% equity securities and 45% other fixed income securities. Over time, as the plan's funded ratio (as defined by the investment policy) improves, in order to reduce volatility in returns and to better match the plan's liabilities, the allocation to equity securities will decrease while the amount allocated to fixed income securities will increase. The plan's assets are managed by a third-party investment manager.

*International plan* – As mentioned above, the plan covering eligible U.K. employees was transferred to the buyer in connection with the sale of our U.K. business during 2019.

***Fair value measurements*** – Plan assets are measured at fair value. The following provides a description of the valuation techniques employed for each major plan asset class at December 31, 2021 and 2020.

*Cash and cash equivalents* – Cash and cash equivalents are valued using a market approach and are considered Level 1.

*Equity securities* – Investments in common stock are valued using a market approach at the closing price reported in an active market and are therefore considered Level 1. Private equity investments include interests in limited partnerships which are valued based on the sum of the estimated fair values of the investments held by each partnership, determined using a combination of market, income and cost approaches, plus working capital, adjusted for liabilities, currency translation and estimated performance incentives. These private equity investments are considered Level 3.

*Other* – Other investments are comprised of an unallocated annuity contract, two limited liability companies and real estate. All are considered Level 3, as significant inputs to determine fair value are unobservable.

*Commingled funds* – The investment in the commingled funds are valued using the net asset value of units held as a practical expedient. The commingled funds consist of equity and fixed income portfolios with underlying investments held in U.S. and non-U.S. securities.

The following tables present the fair values of our defined benefit pension plan's assets, by level within the fair value hierarchy, as of December 31, 2021 and 2020.

| | December 31, 2021 | | | |
|---|---|---|---|---|
| *(In millions)* | **Level 1** | **Level 2** | **Level 3** | **Total** |
| Cash and cash equivalents[(a)] | $ (1) | $ — | $ — | $ (1) |
| **Equity securities:** | | | | |
| Common stock | 28 | — | — | 28 |
| Private equity | — | — | 7 | 7 |
| Other | — | — | 16 | 16 |
| Total investments, at fair value | 27 | — | 23 | 50 |
| Commingled funds[(b)] | — | — | — | 142 |
| Total investments | $ 27 | $ — | $ 23 | $ 192 |

| | December 31, 2020 | | | |
|---|---|---|---|---|
| *(In millions)* | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Equity securities:** | | | | |
| Common stock | $ 61 | $ — | $ — | $ 61 |
| Private equity | — | — | 8 | 8 |
| Other | — | — | 18 | 18 |
| Total investments, at fair value | 61 | — | 26 | 87 |
| Commingled funds[(b)] | — | — | — | 107 |
| Total investments | $ 61 | $ — | $ 26 | $ 194 |

(a) The negative cash balance was due to the timing of when investment trades occur and when they settle.
(b) After the adoption of the FASB update for the fair value hierarchy, we separately report the investments for which fair value was measured using the net asset value per share as a practical expedient. Amounts presented in this table are intended to reconcile the fair value hierarchy to the pension plan assets.

The activity during the year ended December 31, 2021 and 2020, for the assets using Level 3 fair value measurements was immaterial.

***Cash flows***

*Estimated future benefit payments* – The following gross benefit payments, which were estimated based on actuarial assumptions applied at December 31, 2021 and reflect expected future services, as appropriate, are to be paid in the years indicated.

| *(In millions)* | **Pension Benefits** | **Other Benefits** |
|---|---|---|
| 2022 | $ 29 | $ 10 |
| 2023 | 27 | 9 |
| 2024 | 25 | 8 |
| 2025 | 23 | 7 |
| 2026 | 22 | 6 |
| 2027 through 2031 | $ 101 | $ 22 |

*Contributions to defined benefit plans* – We expect to make contributions to the funded pension plan of up to $17 million in 2022. Cash contributions to be paid from our general assets for the unfunded portion of our pension and postretirement plans are expected to be approximately $3 million and $10 million in 2022.

*Contributions to defined contribution plans* – We contribute to several defined contribution plans for eligible employees. Contributions to these plans totaled $13 million in each of 2021 and 2020, and $18 million in 2019.

## 21. Reclassifications Out of Accumulated Other Comprehensive Income (Loss)

The following table presents a summary of amounts reclassified from accumulated other comprehensive income (loss):

| *(In millions)* | Year Ended December 31, 2021 | 2020 | Income Statement Line |
|---|---|---|---|
| **Postretirement and postemployment plans** | | | |
| Amortization of prior service credit | $ 22 | $ 24 | Other net periodic benefit credits |
| Amortization of actuarial loss | (7) | (11) | Other net periodic benefit credits |
| Net settlement loss | (9) | (30) | Other net periodic benefit credits |
| Net curtailment gain | — | 17 | Other net periodic benefit credits |
| **Interest rate swaps** | | | |
| Reclassification of de-designated forward interest rate swaps | (28) | — | Net interest and other |
| Total reclassifications of (income) expense, net of tax [(a)] | $ (22) | $ — | Net income (loss) |

(a) During 2021 and 2020 we had a full valuation allowance on net federal deferred tax assets in the U.S. and as such, there is no tax impact to our postretirement and postemployment plans.

## 22. Supplemental Cash Flow Information

| *(In millions)* | Year Ended December 31, 2021 | 2020 | 2019 |
|---|---|---|---|
| **Included in operating activities:** | | | |
| Interest paid, net of amounts capitalized | $ 231 | $ 251 | $ 253 |
| Income taxes paid to (received from) taxing authorities, net of refunds[(a)] | 24 | (51) | 73 |
| **Noncash investing activities:** | | | |
| Increase (decrease) in asset retirement costs | $ 56 | $ — | $ 80 |
| Asset retirement obligations assumed by buyer[(b)] | — | — | 1,082 |

(a) 2021, 2020 and 2019 includes $2 million, $94 million and $90 million, respectively, related to tax refunds.
(b) In 2019, our dispositions include the sale of the Droshky field (Gulf of Mexico), the sale of our non-operated interest in the Atrush block in Kurdistan and the sale of our U.K. business. See **Note 5** for further detail on dispositions.

Other noncash investing activities include accrued capital expenditures as of December 31, 2021, 2020 and 2019 of $81 million, $95 million and $288 million.

## 23. Other Items

*Net interest and other*

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | 2021 | 2020 | 2019 |
| **Interest:** | | | |
| Interest income | $ 1 | $ 5 | $ 25 |
| Interest expense | (257) | (279) | (280) |
| Gain on interest rate swaps | 54 | 12 | — |
| Total interest | (202) | (262) | (255) |
| **Other:** | | | |
| Net foreign currency gain | — | — | 4 |
| Other | 14 | 6 | 7 |
| Total other | 14 | 6 | 11 |
| Net interest and other | $ (188) | $ (256) | $ (244) |

*Foreign currency* – For the years ended December 31, 2021 and 2020, there were no aggregate foreign currency gains included in the consolidated statements of income. For the year ended December 31, 2019, the aggregate foreign currency gains included in the consolidated statements of income were immaterial.

## 24. Equity Method Investments

During 2021, 2020 and 2019 our equity method investees were considered related parties. Our investment in our equity method investees are summarized in the following table:

| | Ownership as of | December 31, | |
|---|---|---|---|
| *(In millions)* | December 31, 2021 | 2021 | 2020 |
| EGHoldings [(a)] | 56% | $ 148 | $ 113 |
| Alba Plant LLC [(b)] | 52% | 154 | 168 |
| AMPCO [(c)] | 45% | 148 | 166 |
| Total | | $ 450 | $ 447 |

(a) EGHoldings is engaged in LNG production activity.
(b) Alba Plant LLC processes LPG.
(c) AMPCO is engaged in methanol production activity.

In accordance with agreements related to the processing of third-party Alen Unit gas at EGLNG, additional equity was issued to an equity partner, which is an E.G. government entity, during the fourth quarter of 2021, thereby reducing our ownership interest in EGHoldings from 60% to 56%. As a result, we recorded a $12 million pre-tax loss, which was reflected in Net gain (loss) on disposal of assets in our consolidated statements of income.

During the year ended December 31, 2020, we recorded impairments of $171 million to an investment in an equity method investee, which was reflected in income (loss) from equity method investments in our consolidated statements of income. The impairments caused us to incur a basis differential between the net book value of our investment and the amount of our underlying share of equity in the investee's net assets. As of December 31, 2021, the amount of this basis differential was $112 million, which includes the effects of the current year's accretion. During 2021, we accreted $22 million of the basis differential into the income (loss) from equity method investments line item. See **Note 12** to the consolidated financial statements for further information on the equity method investee impairment.

Summarized financial information for equity method investees is as follows:

| *(In millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| **Income data – year:** | | | |
| Revenues and other income | $ 1,095 | $ 586 | $ 832 |
| Income from operations | 537 | 16 | 250 |
| Net income (loss) | 440 | (3) | 187 |
| **Balance sheet data – December 31:** | | | |
| Current assets | $ 556 | $ 389 | |
| Noncurrent assets | 822 | 941 | |
| Current liabilities | 247 | 235 | |
| Noncurrent liabilities | 231 | 170 | |

Revenues from related parties were $30 million, $38 million and $42 million in 2021, 2020 and 2019, respectively, with the majority related to EGHoldings in all years.

Current receivables from related parties at December 31, 2021 and 2020 were $23 million and $24 million, with the majority related to EGHoldings in both periods. Payables to related parties at December 31, 2021 were $20 million and $13 million at December 31, 2020, with the majority related to Alba Plant LLC in both periods.

## 25. Stockholders' Equity

During the fourth quarter 2021, we resumed our share repurchase program and repurchased 46 million shares of our common stock at a cost of $724 million. Effective November 3, 2021, our Board of Directors increased our remaining share repurchase program authorization from $1.1 billion to $2.5 billion. As of December 31, 2021, $1.9 billion of share repurchase program authorization remains. Additionally, we repurchased $10 million of shares during the year ended December 31, 2021 related to our tax withholding obligation associated with the vesting of employee restricted stock awards; these repurchases do not impact our share repurchase program authorization. During 2020, we acquired approximately 9 million of common shares at a cost of $85 million, which were held as treasury stock.

Subsequent to December 31, 2021, we repurchased approximately $258 million of shares of our common stock through February 16, 2022.

Purchases under the program are made at our discretion and may be in either open market transactions, including block purchases, or in privately negotiated transactions using cash on hand, cash generated from operations or proceeds from potential asset sales. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion.

## 26. Commitments and Contingencies

In the second quarter of 2019, Marathon E.G. Production Limited ("MEGPL"), a consolidated and wholly owned subsidiary, signed a series of agreements to process third-party Alen Unit gas through existing infrastructure located in Punta Europa, E.G. Our equity method investee, Alba Plant LLC, is also a party to some of the agreements. These agreements require (subject to certain limitations) MEGPL to indemnify the owners of the Alen Unit against injury to Alba Plant LLC's personnel and damage to or loss of Alba Plant LLC's automobiles, as well as third party claims caused by Alba Plant LLC and certain environmental liabilities arising from certain hydrocarbons in the custody of Alba Plant LLC. At this time, we cannot reasonably estimate this obligation as we do not have any history of prior indemnification claims or environmental discharge or contamination. Therefore, we have not recorded a liability with respect to these indemnities since the amount of potential future payments under these indemnification clauses is not determinable.

The agreements to process the third-party Alen Unit gas required the execution of third-party guarantees by Marathon Oil Corporation in favor of the Alen Unit's owners. Two separate guarantees were executed during the second quarter of 2020; one for a maximum of approximately $91 million pertaining to the payment obligations of Equatorial Guinea LNG Operations, S.A. and another for a maximum of $25 million pertaining to the payment obligations of Alba Plant LLC. Payment by us would be required if any of those entities fails to honor its payment obligations pursuant to the relevant agreements with the owners of the Alen Unit. Certain owners of the Alen Unit, or their affiliates, are also direct or indirect shareholders in Equatorial Guinea LNG Operations, S.A. and Alba Plant LLC. Each guarantee expires no later than December 31, 2027. We measured these guarantees at fair value using the net present value of premium payments we expect to receive from our investees. Our liability for these guarantees was approximately $4 million as of December 31, 2021. Each of Equatorial Guinea LNG Operations, S.A. and Equatorial Guinea LNG Train 1, S.A. provided us with a pledge of its receivables as recourse against any payments we may make under the guaranty of Equatorial Guinea LNG Operations, S.A.'s performance.

Various groups, including the State of North Dakota and three Indian tribes (the "Three Affiliated Tribes") represented by the Bureau of Indian Affairs, have been involved in a dispute regarding the ownership of certain lands underlying the Missouri River and Little Missouri River (the "Disputed Land") from which we currently produce. As a result, as of December 31, 2021, we have a $134 million current liability in suspended royalty and working interest revenue, including interest, of which $122 million was included within accounts payable and $12 million related to accrued interest and was included within other current liabilities on our consolidated balance sheet. Additionally, we have a long-term receivable of $24 million for capital and expenses. The United States Department of the Interior ("DOI") has addressed the United States' position with respect to this dispute several times over the past five years with conflicting opinions. In January 2017, the DOI issued an opinion that the Disputed Land is held in trust for the Three Affiliated Tribes, then in June 2018 and May 2020 the DOI issued opinions concluding that the State of North Dakota held title to the Disputed Land. Most recently, on February 4, 2022, the DOI issued an opinion ("M-Opinion") concluding the DOI's position that the Disputed Land is held in trust for the Three Affiliated Tribes. While the M-Opinion is binding on all agencies within the DOI, it is not legally binding on third parties, including Marathon Oil, or a court. Depending on the ultimate outcome of this title dispute, the Three Affiliated Tribes could challenge the validity of certain of our leases relating to a portion of the disputed land, and if such challenge were successful it could result in operational delays and additional costs to us. Given the uncertainty in matters such as these, we are unable to predict the ultimate outcome of this matter at this time; however, we believe the resolution of this matter will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

In January 2020, we received a Notice of Violation from the EPA related to the Clean Air Act. We have received an initial draft consent decree from the EPA containing certain proposed injunctive terms relating to this enforcement action, and are actively negotiating the terms of the consent decree at this time. The enforcement action will likely result in monetary sanctions and injunctive terms, which may increase our development costs, operating costs or both. Given the uncertainty in matters such as these, we are unable to predict the ultimate outcome of this matter at this time. However, we believe that any penalties, mitigation costs or corrective actions that may result from this matter will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

We are a defendant in a number of legal and administrative proceedings arising in the ordinary course of business including, but not limited to, royalty claims, contract claims, tax disputes and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. In addition, we may also be subject to retained liabilities with respect to certain divested assets by operation of law. For example, the declines in commodity prices during 2020 created an environment where there is an increased risk that owners and/or operators of assets purchased from us may no longer be able to satisfy plugging or abandonment obligations that attach to those assets. In that event, due to operation of law, we may be required to assume plugging or abandonment obligations for those assets. Although we have established reserves for such liabilities, we could be required to accrue additional amounts in the future and these amounts could be material. For instance, as the result of the declaration of bankruptcy by a third party that is the indirect successor in title to certain offshore assets that we previously divested, in 2021 we increased our existing reserve to $37 million related to the anticipated cost to decommission certain wells, pipelines and production facilities. We no longer own these assets nor are they related to our current operations.

Marathon Oil has been named in various lawsuits alleging royalty underpayments in our domestic operations, and plaintiffs in some of these lawsuits are seeking class certification. For instance, Marathon Oil has been named in a lawsuit alleging improper royalty deductions in certain of our Oklahoma operations, and plaintiffs are seeking class certification. We intend to vigorously defend ourselves against such claims. Although we have accrued for potential liabilities associated with these lawsuits, those accruals are based on currently available information and involve elements of judgment and significant uncertainties. Accordingly, actual losses may exceed our accruals or we could be required to accrue additional amounts in the future and these amounts could be material.

*Environmental matters* – We have incurred and will continue to incur capital, operating and maintenance and remediation expenditures as a result of environmental laws and regulations. If these expenditures, as with all costs, are not ultimately offset by the prices we receive for our products and services, our operating results will be adversely affected. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas and production processes. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance.

At December 31, 2021 and 2020, accrued liabilities for remediation were not material. It is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties that may be imposed.

*Guarantees* – Over the years, we have sold various assets in the normal course of our business. Certain of the related agreements contain performance and general guarantees, including guarantees regarding inaccuracies in representations, warranties, covenants and agreements and environmental and general indemnifications that require us to perform upon the occurrence of a triggering event or condition. These guarantees and indemnifications are part of the normal course of selling assets. We are typically not able to calculate the maximum potential amount of future payments that could be made under such contractual provisions because of the variability inherent in the guarantees and indemnities. Most often, the nature of the guarantees and indemnities is such that there is no appropriate method for quantifying the exposure because the underlying triggering event has little or no past experience upon which a reasonable prediction of the outcome can be based.

***Supplementary Information on Oil and Gas Producing Activities (Unaudited)***

The supplementary information is disclosed by the following geographic areas: the U.S.; E.G.; and Other International ("Other Int'l"), which includes the U.K. and the Kurdistan Region of Iraq. For further details on our dispositions that affect the information included in this supplemental information, see **Note 5**.

***Preparation of Reserve Estimates***

All estimates of reserves are made in compliance with SEC Rule 4-10 of Regulation S-X. Crude oil and condensate, NGLs, and natural gas reserve estimates are reviewed and approved by our Corporate Reserves Group ("CRG"), which includes our Vice President of Corporate Reserves and his staff of Reserve Coordinators. Crude oil and condensate, NGLs and natural gas reserve estimates are developed or reviewed by Qualified Reserves Estimators ("QREs"). QREs are petro-technical professionals embedded within the asset teams who meet the qualifications we have established for employees engaged in estimating reserves. QREs have the education, experience and training necessary to estimate reserves in a manner consistent with all external reserve estimation regulations. QREs generally hold at least a Bachelor of Science degree in the appropriate technical field, have a minimum of five years of industry experience with at least three years in reserve estimation and have completed our QRE training course. All reserves changes (including proved) are approved by asset leadership and the CRG. Additionally, any change to proved reserve estimates in excess of 5 mmboe on a total field basis, within a single quarter, must be approved by the Vice President of Corporate Reserves.

The Vice President of Corporate Reserves, who reports to our Executive Vice President and Chief Financial Officer, has a Bachelor of Science degree in petroleum engineering and is a registered Professional Engineer in Texas and Colorado. He has held numerous engineering and management roles in his 23 years of experience in the industry and is a member of the Society of Petroleum Engineers ("SPE").

Technologies used in proved reserves estimation includes statistical analysis of production performance, decline curve analysis, pressure and rate transient analysis, pressure gradient analysis, reservoir simulation and volumetric analysis. The observed statistical nature of production performance coupled with highly certain reservoir continuity or quality and sufficient proved developed locations establish the reasonable certainty criteria required for booking proved reserves.

***Audits of Estimates***

We have established a robust series of internal controls, policies and processes intended to ensure the quality and accuracy of our internal reserve estimates. We also engage third-party consultants to audit our estimates of proved reserves. Our policy requires that audits are provided that comprise at least 80% of our total proved reserves over a rolling four-year period, adjusted for dispositions. In calculating our proved reserve audit coverage percentage, we only include the most recent year a field was audited within the rolling four-year period. An audit tolerance at a field level of +/- 10% to our internal estimates has been established.

Third-party audits were conducted for proved reserves in:

- Bakken and Northern Delaware as of December 31, 2021;
- Alba Field as of December 31, 2019, and
- Eagle Ford and Oklahoma as of December 31, 2018.

On a four-year rolling basis, third-party audits covered 97% of total proved reserves, excluding any dispositions and net of production since the audit "as-of" date. All audits conducted during this period fell within the established +/- 10% tolerance.

Ryder Scott Company performed audits for reserve estimates of our fields as of December 31, 2021 and 2018. Their summary reports are filed as exhibits to this Annual Report on Form 10-K. The team lead for Ryder Scott has over 40 years of industry experience and experience with E&P companies and a major financial advisory services group before joining Ryder Scott over 20 years. He is a 45 year member of the Society of Petroleum Evaluation Engineers ("SPEE"), past president of SPEE, current chairman of SPE Oil & Gas Reserves Committee and is a registered Professional Engineer in the State of Texas.

Netherland, Sewell & Associates, Inc. ("NSAI") performed an audit for reserve estimates of Alba field as of December 31, 2019. The NSAI summary report is filed as an exhibit to this Annual Report on Form 10-K. Members of the NSAI team have multiple years of industry experience, having worked for large, international oil and gas companies before joining NSAI. The senior technical advisor has over 17 years of practical experience in petroleum engineering and the estimation and evaluation of reserves and is a registered Professional Engineer in the State of Texas. The second team member has over 15 years of practical experience in petroleum geosciences and is a licensed Professional Geoscientist in the State of Texas.

### *Estimated Quantities of Proved Oil and Gas Reserves*

The estimation of net recoverable quantities of crude oil and condensate, NGLs and natural gas is a highly technical process which is based upon several underlying assumptions that are subject to change. Proved reserves are determined using "SEC Pricing", calculated as an unweighted average of commodity prices in the prior 12-month period using the closing prices on the first day of each month. As discussed in **Item 1A. Risk Factors** and **Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Estimates**, commodity prices are volatile which can have an impact on proved reserves. If commodity prices in the future average below prices used to determine proved reserves at December 31, 2021, it could have an adverse effect on our estimates of proved reserve volumes and the value of our business. Future reserve revisions could also result from changes in capital funding, drilling plans and governmental regulation, among other things. It is difficult to estimate the magnitude of any potential price change and the effect on proved reserves, due to numerous factors (including future commodity price and performance revisions).

The table below provides the 2021 SEC pricing for certain benchmark prices:

| | 2021 SEC Pricing |
|---|---|
| WTI crude oil *(per bbl)* | $ 66.56 |
| Henry Hub natural gas *(per mmbtu)* | $ 3.60 |
| Brent crude oil *(per bbl)* | $ 69.47 |
| Mont Belvieu NGLs *(per bbl)* | $ 28.57 |

*Supplementary Information on Oil and Gas Producing Activities (Unaudited)*

## *Estimated Quantities of Proved Oil and Gas Reserves*

| *(mmbbl)* | U.S. | E.G.[a] | Other Int'l[b] | Total |
|---|---|---|---|---|
| **Crude oil and condensate** | | | | |
| **Proved developed and undeveloped reserves:** | | | | |
| **Beginning of year - 2019** | 595 | 36 | 25 | 656 |
| Revisions of previous estimates | 34 | 3 | — | 37 |
| Purchases of reserves in place | 9 | — | — | 9 |
| Extensions, discoveries and other additions | 53 | — | — | 53 |
| Production | (69) | (6) | (2) | (77) |
| Sales of reserves in place | (3) | — | (23) | (26) |
| **End of year - 2019** | 619 | 33 | — | 652 |
| Revisions of previous estimates | (86) | (2) | — | (88) |
| Extensions, discoveries and other additions | 16 | — | — | 16 |
| Production | (65) | (5) | — | (70) |
| Sales of reserves in place | (1) | — | — | (1) |
| **End of year - 2020** | 483 | 26 | — | 509 |
| Revisions of previous estimates | 82 | 7 | — | 89 |
| Purchases of reserves in place | 3 | — | — | 3 |
| Extensions, discoveries and other additions | 32 | — | — | 32 |
| Production | (59) | (4) | — | (63) |
| **End of year - 2021** | 541 | 29 | — | 570 |
| **Proved developed reserves:** | | | | |
| Beginning of year - 2019 | 287 | 36 | 22 | 345 |
| End of year - 2019 | 304 | 30 | — | 334 |
| End of year - 2020 | 301 | 23 | — | 324 |
| End of year - 2021 | 332 | 26 | — | 358 |
| **Proved undeveloped reserves:** | | | | |
| Beginning of year - 2019 | 308 | — | 3 | 311 |
| End of year - 2019 | 315 | 3 | — | 318 |
| End of year - 2020 | 182 | 3 | — | 185 |
| End of year - 2021 | 209 | 3 | — | 212 |

### *Estimated Quantities of Proved Oil and Gas Reserves (continued)*

| *(mmbbl)* | U.S. | E.G.[(a)] | Other Int'l[(b)] | Total |
|---|---|---|---|---|
| **Natural gas liquids** | | | | |
| **Proved developed and undeveloped reserves:** | | | | |
| **Beginning of year - 2019** | 224 | 22 | — | 246 |
| Revisions of previous estimates | (21) | 2 | — | (19) |
| Purchases of reserves in place | 5 | — | — | 5 |
| Extensions, discoveries and other additions | 19 | — | — | 19 |
| Production | (22) | (3) | — | (25) |
| Sales of reserves in place | (1) | — | — | (1) |
| **End of year - 2019** | 204 | 21 | — | 225 |
| Revisions of previous estimates | (33) | (2) | — | (35) |
| Extensions, discoveries and other additions | 6 | — | — | 6 |
| Production | (22) | (3) | — | (25) |
| **End of year - 2020** | 155 | 16 | — | 171 |
| Revisions of previous estimates | 50 | 4 | — | 54 |
| Purchases of reserves in place | 1 | — | — | 1 |
| Extensions, discoveries and other additions | 17 | — | — | 17 |
| Production | (23) | (2) | — | (25) |
| **End of year - 2021** | 200 | 18 | — | 218 |
| **Proved developed reserves:** | | | | |
| Beginning of year - 2019 | 119 | 22 | — | 141 |
| End of year - 2019 | 122 | 19 | — | 141 |
| End of year - 2020 | 110 | 14 | — | 124 |
| End of year - 2021 | 135 | 17 | — | 152 |
| **Proved undeveloped reserves:** | | | | |
| Beginning of year - 2019 | 105 | — | — | 105 |
| End of year - 2019 | 82 | 2 | — | 84 |
| End of year - 2020 | 45 | 2 | — | 47 |
| End of year - 2021 | 65 | 1 | — | 66 |

***Estimated Quantities of Proved Oil and Gas Reserves (continued)***

| *(bcf)* | U.S. | E.G.[(a)] | Other Int'l[(b)] | Total |
|---|---|---|---|---|
| **Natural gas** | | | | |
| **Proved developed and undeveloped reserves:** | | | | |
| **Beginning of year - 2019** | 1,553 | 715 | 7 | 2,275 |
| Revisions of previous estimates | (223) | 108 | — | (115) |
| Purchases of reserves in place | 28 | — | — | 28 |
| Extensions, discoveries and other additions | 118 | — | — | 118 |
| Production[(c)] | (160) | (133) | (3) | (296) |
| Sales of reserves in place | (38) | — | (4) | (42) |
| **End of year - 2019** | 1,278 | 690 | — | 1,968 |
| Revisions of previous estimates | 7 | 5 | — | 12 |
| Extensions, discoveries and other additions | 45 | — | — | 45 |
| Production[(c)] | (155) | (121) | — | (276) |
| Sales of reserves in place | (1) | — | — | (1) |
| **End of year - 2020** | 1,174 | 574 | — | 1,748 |
| Revisions of previous estimates | 294 | (13) | — | 281 |
| Purchases of reserves in place | 3 | — | — | 3 |
| Extensions, discoveries and other additions | 113 | — | — | 113 |
| Production | (138) | (95) | — | (233) |
| **End of year - 2021** | 1,446 | 466 | — | 1,912 |
| **Proved developed reserves:** | | | | |
| Beginning of year - 2019 | 869 | 715 | 7 | 1,591 |
| End of year - 2019 | 825 | 649 | — | 1,474 |
| End of year - 2020 | 827 | 526 | — | 1,353 |
| End of year - 2021 | 998 | 439 | — | 1,437 |
| **Proved undeveloped reserves:** | | | | |
| Beginning of year - 2019 | 684 | — | — | 684 |
| End of year - 2019 | 453 | 41 | — | 494 |
| End of year - 2020 | 347 | 48 | — | 395 |
| End of year - 2021 | 448 | 27 | — | 475 |

***Estimated Quantities of Proved Oil and Gas Reserves (continued)***

| *(mmboe)* | U.S. | E.G.[(a)] | Other Int'l[(b)] | Total |
|---|---|---|---|---|
| **Total Proved Reserves** | | | | |
| **Proved developed and undeveloped reserves:** | | | | |
| **Beginning of year - 2019** | 1,078 | 176 | 27 | 1,281 |
| Revisions of previous estimates | (23) | 24 | — | 1 |
| Purchases of reserves in place | 18 | — | — | 18 |
| Extensions, discoveries and other additions | 91 | — | — | 91 |
| Production[(c)] | (117) | (31) | (3) | (151) |
| Sales of reserves in place | (11) | — | (24) | (35) |
| **End of year - 2019** | 1,036 | 169 | — | 1,205 |
| Revisions of previous estimates | (118) | (4) | — | (122) |
| Extensions, discoveries and other additions | 30 | — | — | 30 |
| Production | (112) | (28) | — | (140) |
| Sales of reserves in place | (1) | — | — | (1) |
| **End of year - 2020** | 835 | 137 | — | 972 |
| Revisions of previous estimates | 179 | 10 | — | 189 |
| Purchases of reserves in place | 4 | — | — | 4 |
| Extensions, discoveries and other additions | 68 | — | — | 68 |
| Production | (104) | (23) | — | (127) |
| **End of year - 2021** | 982 | 124 | — | 1,106 |
| **Proved developed reserves:** | | | | |
| Beginning of year - 2019 | 552 | 176 | 24 | 752 |
| End of year - 2019 | 563 | 158 | — | 721 |
| End of year - 2020 | 549 | 125 | — | 674 |
| End of year - 2021 | 634 | 115 | — | 749 |
| **Proved undeveloped reserves:** | | | | |
| Beginning of year - 2019 | 526 | — | 3 | 529 |
| End of year - 2019 | 473 | 11 | — | 484 |
| End of year - 2020 | 286 | 12 | — | 298 |
| End of year - 2021 | 348 | 9 | — | 357 |

(a) Consists of estimated reserves from properties governed by production sharing contracts.

(b) In 2019, we closed on the sale of our U.K. business and our non-operated interested in the Atrush block of Kurdistan. These volumes are reflected in Other Int’l in the tables above for the periods presented.

(c) Excludes the resale of purchased natural gas used in reservoir management.

2021 proved reserves increased by 134 mmboe primarily due to the following:

- ***Revisions of previous estimates:*** Increased by 189 mmboe as referenced below:

  **Increases:**
  - 108 mmboe associated with improved commodity pricing
  - 56 mmboe associated with changes in the 5-year plan in U.S. resource plays
  - 25 mmboe associated with wells to sales from unproved categories
  - 21 mmboe associated with performance and other technical revisions

  **Decreases:**
  - 21 mmboe due to increased operational costs
- ***Extensions, discoveries and other additions:*** Increased by 68 mmboe in the U.S. resource plays primarily due to expansion of proved areas
- ***Production:*** Decreased by 127 mmboe.

2020 proved reserves decreased by 233 mmboe primarily due to the following:

- ***Revisions of previous estimates:*** Decreased by 122 mmboe as referenced below:

  **Increases:**
  - 46 mmboe associated with technical revisions, including lower operating costs

  **Decreases:**
  - 130 mmboe due to decreased capital activity in the forecasted 5-year plan in the U.S. resource plays
  - 38 mmboe due to reduced commodity prices
- ***Extensions, discoveries and other additions:*** Increased by 30 mmboe in the U.S. resource plays as referenced below:

  **Increases:**
  - 18 mmboe associated with wells to sales from unproved categories
  - 12 mmboe associated with the expansion of proved areas
- ***Production:*** Decreased by 140 mmboe.

2019 proved reserves decreased by 76 mmboe primarily due to the following:

- ***Revisions of previous estimates:*** Increased by 1 mmboe as referenced below:

  **Increases:**
  - 20 mmboe associated with wells to sales that were additions to the plan
  - 11 mmboe associated with planned compression in E.G.
  - 11 mmboe due to technical revisions in E.G.

  **Decreases:**
  - 24 mmboe due to reduced commodity pricing
  - 12 mmboe due to technical revisions in the U.S. resource plays
  - 5 mmboe due to changes in the 5-year plan in the U.S. resource plays
- ***Purchases of reserves in place:*** Increased by 18 mmboe due to the acquisition in the Eagle Ford.
- ***Extensions, discoveries and other additions**:* Increased by 91 mmboe in the U.S. resource plays as referenced below:

  **Increases:**
  - 53 mmboe associated with the expansion of proved areas
  - 38 mmboe associated with wells to sales from unproved categories
- ***Production:*** Decreased by 151 mmboe.
- ***Sales of reserves in place:*** Decreased by 35 mmboe as referenced below:

  **Decreases:**
  - 19 mmboe associated with the sale of assets in the U.K.
  - 11 mmboe associated with divestitures of certain U.S. assets
  - 5 mmboe associated with the sale of the Atrush block in Kurdistan

***Supplementary Information on Oil and Gas Producing Activities (Unaudited)***

***Changes in Proved Undeveloped Reserves***

The following table shows changes in proved undeveloped reserves for 2021:

| *(mmboe)* | |
|---|---|
| Beginning of year | 298 |
| Revisions of previous estimates | 62 |
| Purchases of reserves in place | 1 |
| Extensions, discoveries and other additions | 66 |
| Transfers to proved developed | (70) |
| End of year | 357 |

2021 proved undeveloped reserves increased by 59 mmboe primarily due to the following:

***Revisions of prior estimates:*** Increased by 62 mmboe as referenced below:

**Increases:**

- 56 mmboe associated with changes in the 5-year plan in U.S. resource plays
- 14 mmboe associated with improved commodity pricing

**Decreases:**

- 6 mmboe due to increased operational costs

***Extensions, discoveries and other additions:*** Increased by 66 mmboe associated with expansion of proved areas in U.S. resource plays.

***Transfers to proved developed:*** 70 mmboe of PUD reserves were converted to proved developed status during 2021 from assets in our U.S. resource plays. This 2021 transfer equates to a 23% PUD conversion rate and a 5-year average annual PUD conversion rate during the 2017-2021 period of 19%. All proved undeveloped reserve drilling locations are scheduled to be producing within five years of the initial booking date.

## Capitalized Costs and Accumulated Depreciation, Depletion and Amortization

| *(In millions)* | U.S. | E.G. | Total |
|---|---|---|---|
| **Year Ended December 31, 2021** | | | |
| Capitalized Costs: | | | |
| Proved properties | $ 31,626 | $ 2,056 | $ 33,682 |
| Unproved properties | 2,409 | — | 2,409 |
| Total | 34,035 | 2,056 | 36,091 |
| Accumulated depreciation, depletion and amortization: | | | |
| Proved properties | 19,609 | 1,716 | 21,325 |
| Unproved properties[(a)] | 413 | (7) | 406 |
| Total | 20,022 | 1,709 | 21,731 |
| Net capitalized costs | $ 14,013 | $ 347 | $ 14,360 |
| **Year Ended December 31, 2020** | | | |
| Capitalized Costs: | | | |
| Proved properties | $ 30,398 | $ 2,057 | $ 32,455 |
| Unproved properties | 2,721 | — | 2,721 |
| Total | 33,119 | 2,057 | 35,176 |
| Accumulated depreciation, depletion and amortization: | | | |
| Proved properties | 17,616 | 1,650 | 19,266 |
| Unproved properties[(a)] | 433 | (7) | 426 |
| Total | 18,049 | 1,643 | 19,692 |
| Net capitalized costs | $ 15,070 | $ 414 | $ 15,484 |

(a) Includes unproved property impairments (See **Note 12**).

## Costs Incurred for Property Acquisition, Exploration and Development [(a)]

| *(In millions)* | U.S. | E.G. | Other Int'l | Total |
|---|---|---|---|---|
| **December 31, 2021** | | | | |
| Property acquisition: | | | | |
| Proved | $ 47 | $ — | $ — | $ 47 |
| Unproved | 9 | — | — | 9 |
| Exploration | 162 | — | — | 162 |
| Development | 781 | 5 | — | 786 |
| Total | $ 999 | $ 5 | $ — | $ 1,004 |
| **December 31, 2020** | | | | |
| Unproved property acquisition | $ 36 | $ — | $ — | $ 36 |
| Exploration | 330 | — | — | 330 |
| Development | 780 | 9 | — | 789 |
| Total | $ 1,146 | $ 9 | $ — | $ 1,155 |
| **December 31, 2019** | | | | |
| Property acquisition: | | | | |
| Proved | $ 93 | $ — | $ — | $ 93 |
| Unproved | 282 | — | — | 282 |
| Exploration | 862 | — | — | 862 |
| Development | 1,675 | 1 | 23 [(b)] | 1,699 |
| Total | $ 2,912 | $ 1 | $ 23 | $ 2,936 |

(a) Includes costs incurred whether capitalized or expensed.
(b) Includes revisions to asset retirement costs primarily due to changes in U.K. estimated costs as well as timing of abandonment activities.

## Results of Operations for Oil and Gas Producing Activities

| | U.S. | E.G. | Other Int'l | Total |
|---|---|---|---|---|
| **Year Ended December 31, 2021** | | | | |
| Revenues and other income: | | | | |
| Sales | $ 4,828 | $ 265 | $ — | $ 5,093 |
| Other income[(a)] | 9 | — | — | 9 |
| Total revenues and other income | 4,837 | 265 | — | 5,102 |
| Expenses: | | | | |
| Production costs | (1,388) | (56) | — | (1,444) |
| Exploration expenses[(b)] | (136) | — | — | (136) |
| Depreciation, depletion and amortization[(c)] | (2,032) | (68) | — | (2,100) |
| Technical support and other | (38) | (3) | — | (41) |
| Total expenses | (3,594) | (127) | — | (3,721) |
| Results before income taxes | 1,243 | 138 | — | 1,381 |
| Income tax (provision) benefit | (7) | (37) | — | (44) |
| Results of operations | $ 1,236 | $ 101 | $ — | $ 1,337 |
| **Year Ended December 31, 2020** | | | | |
| Revenues and other income: | | | | |
| Sales | $ 2,955 | $ 173 | $ — | $ 3,128 |
| Other income[(a)] | 9 | — | — | 9 |
| Total revenues and other income | 2,964 | 173 | — | 3,137 |
| Expenses: | | | | |
| Production costs | (1,134) | (61) | — | (1,195) |
| Exploration expenses[(b)] | (175) | (6) | — | (181) |
| Depreciation, depletion and amortization[(c)] | (2,260) | (81) | — | (2,341) |
| Technical support and other | (48) | (3) | — | (51) |
| Total expenses | (3,617) | (151) | — | (3,768) |
| Results before income taxes | (653) | 22 | — | (631) |
| Income tax (provision) benefit | 9 | (5) | — | 4 |
| Results of operations | $ (644) | $ 17 | $ — | $ (627) |
| **Year Ended December 31, 2019** | | | | |
| Revenues and other income: | | | | |
| Sales | $ 4,472 | $ 307 | $ 140 | $ 4,919 |
| Other income[(a)] | 46 | — | 3 | 49 |
| Total revenues and other income | 4,518 | 307 | 143 | 4,968 |
| Expenses: | | | | |
| Production costs | (1,384) | (73) | (71) | (1,528) |
| Exploration expenses[(b)] | (149) | — | — | (149) |
| Depreciation, depletion and amortization[(c)] | (2,274) | (97) | (23) | (2,394) |
| Technical support and other | (38) | (9) | (10) | (57) |
| Total expenses | (3,845) | (179) | (104) | (4,128) |
| Results before income taxes | 673 | 128 | 39 | 840 |
| Income tax (provision) benefit | (6) | (32) | 12 | (26) |
| Results of operations | $ 667 | $ 96 | $ 51 | $ 814 |

(a) Includes net gain (loss) on dispositions (See **Note 5**).
(b) Includes exploratory dry well costs, unproved property impairments and other.
(c) Includes long-lived asset impairments (See **Note 12**).

## Results of Operations for Oil and Gas Producing Activities

The following reconciles results of operations for oil and gas producing activities to segment income (loss):

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | **2021** | **2020** | **2019** |
| Results of operations | $ 1,337 | $ (627) | $ 814 |
| Items not included in results of oil and gas operations, net of tax: | | | |
| Marketing income and other non-oil and gas producing related activities | (125) | (135) | (141) |
| Income from equity method investments | 232 | 19 | 87 |
| Items not allocated to segment income, net of tax: | | | |
| Loss (gain) on asset dispositions and other | 37 | 62 | — |
| Long-lived asset impairments | 59 | 49 | 24 |
| Exploratory dry well costs and unproved property impairments | 70 | 82 | — |
| Unrealized loss (gain) on derivatives | (16) | 27 | 124 |
| Segment income (loss) | $ 1,594 | $ (523) | $ 908 |

## Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

U.S. GAAP prescribes guidelines for computing the standardized measure of future net cash flows and changes therein relating to estimated proved reserves, giving very specific assumptions to be made such as the use of a 10% discount rate and an unweighted average of commodity prices in the prior 12-month period using the closing prices on the first day of each month as well as current costs applicable at the date of the estimate. These and other required assumptions have not always proved accurate in the past, and other valid assumptions would give rise to substantially different results. In addition, the 10% discount rate required to be used is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the oil and natural gas industry in general. This information is not the fair value nor does it represent the expected present value of future cash flows of our crude oil and condensate, natural gas liquids and natural gas reserves.

| *(In millions)* | U.S. | E.G. | Total |
|---|---|---|---|
| **Year Ended December 31, 2021** | | | |
| Future cash inflows | $ 46,172 | $ 1,734 | $ 47,906 |
| Future production and support costs | (17,212) | (880) | (18,092) |
| Future development costs | (4,459) | (36) | (4,495) |
| Future income tax expenses | (2,526) | (209) | (2,735) |
| Future net cash flows | $ 21,975 | $ 609 | $ 22,584 |
| 10% annual discount for timing of cash flows | (10,000) | (180) | (10,180) |
| Standardized measure of discounted future net cash flows | $ 11,975 | $ 429 | $ 12,404 |
| **Year Ended December 31, 2020** | | | |
| Future cash inflows | $ 21,847 | $ 941 | $ 22,788 |
| Future production and support costs | (10,822) | (592) | (11,414) |
| Future development costs | (3,977) | (19) | (3,996) |
| Future income tax expenses | (12) | (84) | (96) |
| Future net cash flows | $ 7,036 | $ 246 | $ 7,282 |
| 10% annual discount for timing of cash flows | (3,207) | (56) | (3,263) |
| Standardized measure of discounted future net cash flows | $ 3,829 | $ 190 | $ 4,019 |
| **Year Ended December 31, 2019** | | | |
| Future cash inflows | $ 40,487 | $ 1,812 | $ 42,299 |
| Future production and support costs | (14,167) | (838) | (15,005) |
| Future development costs | (7,561) | (18) | (7,579) |
| Future income tax expenses | (1,085) | (280) | (1,365) |
| Future net cash flows | $ 17,674 | $ 676 | $ 18,350 |
| 10% annual discount for timing of cash flows | (7,416) | (179) | (7,595) |
| Standardized measure of discounted future net cash flows | $ 10,258 | $ 497 | $ 10,755 |

## Changes in the Standardized Measure of Discounted Future Net Cash Flows

| *(In millions)* | Year Ended December 31, 2021 | 2020 | 2019 |
|---|---|---|---|
| Sales and transfers of oil and gas produced, net of production and support costs | $ (3,608) | $ (1,889) | $ (3,345) |
| Net changes in prices and production and support costs related to future production | 8,098 | (7,986) | (3,569) |
| Extensions, discoveries and improved recovery, less related costs | 511 | 230 | 718 |
| Development costs incurred during the period | 795 | 801 | 1,727 |
| Changes in estimated future development costs | (219) | 2,693 | 278 |
| Revisions of previous quantity estimates[(a)(b)] | 3,365 | (2,047) | 7 |
| Net changes in purchases and sales of minerals in place | (52) | (9) | (200) |
| Accretion of discount[(b)] | 374 | 1,031 | 1,315 |
| Net change in income taxes | (879) | 440 | 155 |
| Net change for the year | 8,385 | (6,736) | (2,914) |
| Beginning of the year | 4,019 | 10,755 | 13,669 |
| End of the year | $ 12,404 | $ 4,019 | $ 10,755 |

(a) Includes amounts resulting from changes in the timing of production. The year ended 2020 also includes the impact of lower forecasted capital activity in the 5-year plan in our U.S. resource plays.

(b) For the year ended December 31, 2020, adjustments were made to correct an error embedded in the calculation of the Revisions of previous quantity estimates and Accretion of discount line items. The correction resulted in an increase of $3.0 billion in the Revisions of previous quantity estimates line item, with a corresponding decrease of $3.0 billion in the Accretion of discount line item. The correction was completely offsetting and therefore, did not change the beginning or ending values within the table, nor did it impact the valuation of our total proved reserves.

## Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

## Item 9A. Controls and Procedures

### Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. As of the end of the period covered by this Report based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective as of December 31, 2021.

### Management's Annual Report on Internal Control Over Financial Reporting

See "Management's Report on Internal Control over Financial Reporting" under Item 8 of this Form 10-K.

### Attestation Report of the Registered Public Accounting Firm

See "Report of Independent Registered Public Accounting Firm" under Item 8 of this Form 10-K.

### Changes in Internal Control Over Financial Reporting

During the fourth quarter of 2021, there were no changes in our internal control over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

## Item 9B. Other Information

None.

## Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

## PART III

### Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item is incorporated by reference to "Proposal 1: Election of Directors," "Corporate Governance—Committees of the Board" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement for the 2022 Annual Meeting of Stockholders, to be filed with the SEC within 120 days of December 31, 2021 (the "2022 Proxy Statement").

See "Executive Officers of the Registrant" under Item 1 of this Form 10-K for information about our executive officers.

Our code of ethics for Senior Financial Officers, which applies to the Company's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions, is contained in our Code of Business Conduct, which is available on our website at www.marathonoil.com under Investors—Corporate Governance. You may request a printed copy free of charge by sending a request to the Corporate Secretary. We intend to disclose any amendments and any waivers to our Code of Business Conduct that apply to our principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions and relate to any element of the Code of Business Conduct enumerated in Item 406(b) of Regulation S-K on our website at www.marathonoil.com under Investors — Corporate Governance within four business days. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver.

### Item 11. Executive Compensation

Information required by this item is incorporated by reference to "Corporate Governance—Compensation Committee Interlocks and Insider Participation," "Compensation Committee Report," "Director Compensation," "Compensation Discussion and Analysis" and "Executive Compensation" in the 2022 Proxy Statement.

### Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Portions of information required by this item are incorporated by reference to "Security Ownership of Certain Beneficial Owners and Management" in the 2022 Proxy Statement.

### Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2021 with respect to shares of Marathon Oil common stock that may be issued under our existing equity compensation plans:

- Marathon Oil Corporation 2019 Incentive Compensation Plan (the "2019 Plan")
- Marathon Oil Corporation 2016 Incentive Compensation Plan (the "2016 Plan") – No additional awards will be granted under this plan.
- Marathon Oil Corporation 2012 Incentive Compensation Plan (the "2012 Plan") – No additional awards will be granted under this plan.
- Marathon Oil Corporation 2007 Incentive Compensation Plan (the "2007 Plan") – No additional awards will be granted under this plan.

| Plan category | Number of securities to be issued upon exercise of outstanding options, warrants and rights | Weighted-average exercise price of outstanding options, warrants and rights | Number of securities remaining available for future issuance under equity compensation plans |
|---|---|---|---|
| Equity compensation plans approved by stockholders | 7,506,052 | $ 17.50 | 25,948,349 [(a)] |

[(a)] Reflects the shares available for issuance under the 2019 Plan for awards of restricted stocks, restricted stock units, stock-based performance units, stock options and stock appreciation rights. In the case of stock-based performance units, amounts assume target performance.

### Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is incorporated by reference to "Transactions with Related Persons," and "Proposal 1: Election of Directors—Director Independence" in the 2022 Proxy Statement.

### Item 14. Principal Accountant Fees and Services

Information required by this item is incorporated by reference to "Proposal 2: Ratification of Independent Auditor for 2022" in the 2022 Proxy Statement.

## PART IV

### Item 15. Exhibits, Financial Statement Schedules

### A. Documents Filed as Part of the Report

1. Financial Statements – See Part II, Item 8. of this Annual Report on Form 10-K.
2. Financial Statement Schedules – The unaudited financial statements and related footnotes of Alba Plant LLC, our equity method investment, are being filed within Exhibit 99.9 in accordance with Rule 3-09 of Regulation S-X. All other financial statement schedules required under SEC rules but not included in this Annual Report on Form 10-K are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.
3. Exhibits – The information required by this Item 15 is incorporated by reference to the Exhibit Index accompanying this Annual Report on Form 10-K.

### Item 16. Form 10-K Summary

None.

## SIGNATURES

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

February 17, 2022 MARATHON OIL CORPORATION

By: /s/ GARY E. WILSON

Gary E. Wilson

Vice President, Controller and Chief Accounting Officer

## POWER OF ATTORNEY

Each person whose signature appears below appoints Lee M. Tillman, Dane E. Whitehead, and Gary E. Wilson, and each of them, as his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, with full power and authority to each of said attorneys-in-fact and agents to do and perform each and every act whatsoever that is necessary, appropriate or advisable in connection with any or all of the above-described matters and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on February 17, 2022 on behalf of the registrant and in the capacities indicated.

| Signature | Title |
|---|---|
| /s/ LEE M. TILLMAN<br>Lee M. Tillman | Chairman, President and Chief Executive Officer |
| /s/ DANE E. WHITEHEAD<br>Dane E. Whitehead | Executive Vice President and Chief Financial Officer |
| /s/ GARY E. WILSON<br>Gary E. Wilson | Vice President, Controller and Chief Accounting Officer |
| /s/ CHADWICK C. DEATON<br>Chadwick C. Deaton | Director |
| /s/ MARCELA E. DONADIO<br>Marcela E. Donadio | Director |
| /s/ JASON B. FEW<br>Jason B. Few | Director |
| /s/ M.ELISE HYLAND<br>M. Elise Hyland | Director |
| /s/ HOLLI C. LADHANI<br>Holli C. Ladhani | Director |
| /s/ BRENT J. SMOLIK<br>Brent J. Smolik | Director |
| /s/ J.KENT WELLS<br>J. Kent Wells | Director |

**Exhibit Index**

| Exhibit Number | Exhibit Description | Incorporated by Reference (File No. 001-05153, unless otherwise indicated) | | |
|---|---|---|---|---|
| | | Form | Exhibit | Filing Date |
| **1** | **Underwriting Agreement** | | | |
| 1.1 | Bond Purchase Agreement, dated as of November 28, 2017, between Marathon Oil Corporation, the Parish of St. John the Baptist, State of Louisiana, and Morgan Stanley & Co. LLC. | 10-K | 1.1 | 2/22/2018 |
| **2** | **Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession** | | | |
| 2.1 | Share Purchase Agreement, dated as of March 8, 2017, by and among Marathon Oil Dutch Holdings B.V., as Seller, and 10084751 Canada Limited, as a Buyer and Canadian Natural Resources Limited, as a Buyer, in respect of Marathon Oil Canada Corporation. | 10-Q | 10.1 | 5/5/2017 |
| **3** | **Articles of Incorporation and By-laws** | | | |
| 3.1 | Restated Certificate of Incorporation of Marathon Oil Corporation | 8-K | 3.1 | 6/1/2018 |
| 3.2 | Marathon Oil Corporation By-laws (Amended and restated as of February 24, 2016) | 10-Q | 3.2 | 8/4/2016 |
| 3.3 | Specimen of Common Stock Certificate | 10-K | 3.3 | 2/28/2014 |
| **4** | **Instruments Defining the Rights of Security Holders, Including Indentures** | | | |
| 4.1 | Indenture, dated as of February 26, 2002, between Marathon Oil Corporation and The Bank of New York Trust Company, N.A., successor in interest to JPMorgan Chase Bank as Trustee, relating to senior debt securities of Marathon Oil Corporation. Pursuant to CFR 229.601(b)(4)(iii), instruments with respect to long-term debt issues have been omitted where the amount of securities authorized under such instruments does not exceed 10% of the total consolidated assets of Marathon Oil. Marathon Oil hereby agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon its request | 10-K | 4.2 | 2/28/2014 |
| 4.2* | Description of Registrants Securities | | | |
| **10** | **Material Contracts** | | | |
| 10.1 | Amended and Restated Credit Agreement, dated as of May 28, 2014, among Marathon Oil Corporation, as borrower, The Royal Bank of Scotland plc, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions named therein | 8-K | 4.1 | 6/2/2014 |
| 10.2 | First Amendment, dated as of May 5, 2015, to the Amended and Restated Credit Agreement dated as of May 28, 2014, by and among Marathon Oil Corporation, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions named therein | 10-Q | 10.1 | 5/7/2015 |
| 10.3 | Incremental Commitments Supplement, dated as of March 4, 2016, to the Amended and Restated Credit Agreement dated as of May 28, 2014, as amended by the First Amendment dated as of May 5, 2015, among Marathon Oil Corporation, as borrower, the lenders party thereto, The Royal Bank of Scotland Plc, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, and JPMorgan Chase Bank, N.A., as administrative agent. | 8-K | 99.1 | 3/8/2016 |

| Exhibit Number | Exhibit Description | Incorporated by Reference (File No. 001-05153, unless otherwise indicated) | | |
|---|---|---|---|---|
| | | Form | Exhibit | Filing Date |
| 10.4 | Second Amendment, dated as of June 22, 2017, to the Amended and Restated Credit Agreement dated as of May 28, 2014, as amended by the First Amendment dated as of May 5, 2015, and supplemented by the Incremental Commitments Supplement dated as of March 4, 2016, among Marathon Oil Corporation, as borrower, the lenders party thereto, The Royal Bank of Scotland Plc, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, and JPMorgan Chase Bank, N.A., as administrative agent. | 8-K | 99.1 | 6/23/2017 |
| 10.5 | Incremental Commitment Supplement, dated as of July 11, 2017, to the Amended and Restated Credit Agreement dated as of May 28, 2014, as amended by the First Amendment dated as of May 5, 2015, supplemented by the Incremental Commitments Supplement dated as of March 4, 2016, and amended by the Second Amendment dated as of June 22, 2017, among Marathon Oil Corporation, as borrower, the lenders party thereto, The Royal Bank of Scotland Plc, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, and JPMorgan Chase Bank, N.A., as administrative agent. | 10-Q | 10.2 | 8/3/2017 |
| 10.6 | Third Amendment, dated as of October 18, 2018, to the Amended and Restated Credit Agreement dated as of May 28, 2014, as amended by the First Amendment dated as of May 5, 2015 and the Second Amendment dated as of June 22, 2017 and as supplemented by the Incremental Commitments Supplement dated as of March 4, 2016 and Incremental Commitments Supplement dated as July 11, 2017, among Marathon Oil Corporation, as borrower, the lenders party thereto, Mizuho Bank, Ltd, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, and JPMorgan Chase Bank, N.A., as administrative agent | 8-K | 99.1 | 10/22/2018 |
| 10.7 | Fourth Amendment, dated as of September 24, 2019, to the Amended and Restated Credit Agreement dated as of May 28, 2014, as amended by the First Amendment dated as of May 5, 2015, the Second Amendment dated as of June 22, 2017, and the Third Amendment dated as of October 18, 2018 and as supplemented by the Incremental Commitments Supplement dated as of March 4, 2016 and Incremental Commitments Supplement dated as July 11, 2017, among Marathon Oil Corporation, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions named therein | 8-K | 10.1 | 9/24/2019 |
| 10.8 | Fifth Amendment, dated as of December 4, 2020, to the Amended and Restated Credit Agreement dated as of May 28, 2014, as amended by the First Amendment, dated as of May 5, 2015, the Second Amendment, dated as of June 22, 2017, the Third Amendment, dated as of October 18, 2018, and the Fourth Amendment, dated as of September 24, 2019 and as supplemented by the Incremental Commitments Supplement, dated as of March 4, 2016 and Incremental Commitments Supplement, dated as July 11, 2017, among Marathon Oil Corporation, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions named therein | 8-K | 10.1 | 12/8/2020 |

| Exhibit Number | Exhibit Description | Incorporated by Reference (File No. 001-05153, unless otherwise indicated) | | |
|---|---|---|---|---|
| | | Form | Exhibit | Filing Date |
| 10.9 | Sixth Amendment, dated as of June 21, 2021, to the Amended and Restated Credit Agreement dated as of May 28, 2014, as amended by the First Amendment, dated as of May 5, 2015, the Second Amendment, dated as of June 22, 2017, the Third Amendment, dated as of October 18, 2018, the Fourth Amendment, dated as of September 24, 2019, and the Fifth Amendment, dated as of December 4, 2020 and as supplemented by the Incremental Commitments Supplement, dated as of March 4, 2016 and Incremental Commitments Supplement, dated as July 11, 2017, among Marathon Oil Corporation, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions named therein | 8-K | 10.1 | 6/23/2021 |
| 10.10† | 2021 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Restricted Stock Unit Award Agreement for Section 16 Officers | 10-Q | 10.1 | 5/6/2021 |
| 10.11† | 2021 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Performance Unit Award Agreement 2021 - 2022 Performance Cycle for Section 16 Officers | 10-Q | 10.2 | 5/6/2021 |
| 10.12† | 2021 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Performance Unit Award Agreement 2021 - 2023 Performance Cycle for Section 16 Officers | 10-Q | 10.3 | 5/6/2021 |
| 10.13† | 2021 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Restricted Stock Unit Award Agreement for Non-Employee Directors | 10-K | 10.9 | 2/23/2021 |
| 10.14† | Marathon Oil Corporation 2019 Incentive Compensation Plan | DEF 14A | App. A | 4/12/2019 |
| 10.15† | 2019 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Restricted Stock Award Agreement for Section 16 Officers | 10-Q | 10.1 | 8/8/2019 |
| 10.16† | 2019 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Section 16 Officers | 10-Q | 10.2 | 8/8/2019 |
| 10.17† | 2019 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Restricted Stock Unit Award Agreement for Section 16 Officers | 10-Q | 10.3 | 8/8/2019 |
| 10.18† | 2019 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Restricted Stock Unit Award Agreement for Non-Employee Directors | 10-Q | 10.4 | 8/8/2019 |
| 10.19† | 2020 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Performance Unit Award Agreement for Section 16 Officers | 10-K | 10.13 | 2/2/2020 |
| 10.20† | Marathon Oil Corporation 2016 Incentive Compensation Plan | DEF 14A | App. A | 4/7/2016 |
| 10.21† | 2019 Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Restricted Stock Award Agreement for Section 16 Officers | 10-Q | 10.1 | 5/2/2019 |
| 10.22† | 2019 Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Section 16 Officers | 10-Q | 10.2 | 5/2/2019 |
| 10.23† | 2019 Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Restricted Stock Unit Award Agreement for Section 16 Officers | 10-Q | 10.3 | 5/2/2019 |
| 10.24† | 2019 Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Performance Unit Award Agreement for Section 16 Officers | 10-Q | 10.4 | 5/2/2019 |

| Exhibit Number | Exhibit Description | Incorporated by Reference (File No. 001-05153, unless otherwise indicated) | | |
|---|---|---|---|---|
| | | Form | Exhibit | Filing Date |
| 10.25† | Summary Director Compensation Arrangement, effective 2021 | 10-K | 10.21 | 2/23/2021 |
| 10.26† | Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Restricted Stock Award Agreement for Section 16 Officers (3-year cliff vesting) | 8-K/A | 10.1 | 10/6/2016 |
| 10.27† | Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Restricted Stock Award Agreement for Section 16 Officers (3-year prorata vesting) | 10-K | 10.6 | 2/24/2017 |
| 10.28† | Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Section 16 Officers | 10-K | 10.7 | 2/24/2017 |
| 10.29† | Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Restricted Stock Unit Award Agreement for Non-Employee Directors (3-year cliff vesting) | 10-K | 10.8 | 2/24/2017 |
| 10.30† | Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Restricted Stock Unit Award Agreement for Non-Employee Canadian Directors (3-year cliff vesting) | 10-K | 10.9 | 2/24/2017 |
| 10.31† | Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Performance Unit Award Agreement for Section 16 Officers | 10-K | 10.12 | 2/22/2018 |
| 10.32† | Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Performance Unit Award Agreement for Officers | 10-K | 10.13 | 2/22/2018 |
| 10.33† | Marathon Oil Corporation 2012 Incentive Compensation Plan | DEF 14A | App. III | 3/8/2012 |
| 10.34† | Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Non-Qualified Stock Option Award Agreement | 8-K | 10.1 | 8/1/2014 |
| 10.35† | Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Initial CEO Option Grant Agreement | 10-Q | 10.1 | 11/6/2013 |
| 10.36† | Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Section 16 Officers (3-year prorata vesting) | 10-K | 10.5 | 2/22/2013 |
| 10.37† | Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Officers (3-year prorata vesting) | 10-K | 10.6 | 2/22/2013 |
| 10.38† | Marathon Oil Corporation 2007 Incentive Compensation Plan | 10-K | 10.5 | 2/29/2012 |
| 10.39† | Form of Marathon Oil Corporation 2007 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Officers | 10-K | 10.6 | 2/29/2012 |
| 10.40† | Form of Marathon Oil Corporation 2007 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Section 16 Officers | 10-K | 10.5 | 2/28/2011 |
| 10.41† | Marathon Oil Corporation Deferred Compensation Plan for Non-Employee Directors (Amended and Restated as of December 20, 2016) | 10-K | 10.29 | 2/24/2017 |
| 10.42† | Marathon Oil Company Deferred Compensation Plan Amended and Restated Effective June 30, 2011 | 10-K | 10.32 | 2/29/2012 |
| 10.43† | Marathon Oil Company Excess Benefit Plan Amended and Restated | 10-K | 10.31 | 2/29/2012 |
| 10.44† | Marathon Oil Corporation Officer Change in Control Severance Benefits Plan (As amended effective January 27, 2021) | 10-K | 10.40 | 2/23/2021 |
| 10.45† | Marathon Oil Corporation Policy for Repayment of Annual Cash Bonus Amounts | 10-K | 10.10 | 2/28/2011 |

| Exhibit Number | Exhibit Description | Incorporated by Reference (File No. 001-05153, unless otherwise indicated) | | |
|---|---|---|---|---|
| | | Form | Exhibit | Filing Date |
| 10.46† | Marathon Oil Corporation Executive Tax, Estate, and Financial Planning Program, Amended and Restated, Effective January 1, 2009 | 10-K | 10.32 | 2/27/2009 |
| 10.47 | Tax Sharing Agreement dated as of May 25, 2011 among Marathon Oil Corporation, Marathon Petroleum Corporation and MPC Investment LLC | 8-K | 10.1 | 5/26/2011 |
| 21.1* | List of Significant Subsidiaries | | | |
| 23.1* | Consent of Independent Registered Public Accounting Firm | | | |
| 23.2* | Consent of Independent Registered Public Accounting Firm | | | |
| 23.3* | Consent of Ryder Scott Company, L.P., independent petroleum engineers and geologists | | | |
| 23.4* | Consent of Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists | | | |
| 31.1* | Certification of President and Chief Executive Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934 | | | |
| 31.2* | Certification of Chief Financial Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934 | | | |
| 32.1* | Certification of President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350 | | | |
| 32.2* | Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350 | | | |
| 99.1* | Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2021 | | | |
| 99.2* | Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2021 | | | |
| 99.3 | Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2019 | 10-K | 99.1 | 2/23/2021 |
| 99.4 | Summary report of audits performed by Ryder Scott Company, L.P. independent petroleum enginners and geologists for 2018 | 10-K | 99.1 | 2/20/2020 |
| 99.5 | Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2018 | 10-K | 99.2 | 2/20/2020 |
| 99.9* | Alba Plant, LLC financial statements as of December 31, 2021 | | | |
| 101.INS* | XBRL Instance Document - the XBRL Instance Document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document | | | |
| 101.SCH* | XBRL Taxonomy Extension Schema | | | |
| 101.CAL* | XBRL Taxonomy Extension Calculation Linkbase | | | |
| 101.DEF* | XBRL Taxonomy Extension Definition Linkbase | | | |
| 101.LAB* | XBRL Taxonomy Extension Label Linkbase | | | |
| 101.PRE* | XBRL Taxonomy Extension Presentation Linkbase | | | |
| 104* | Cover Page Interactive Data File, formatted in iXBRL and contained in Exhibit 101 | | | |

| | |
|---|---|
| * | Filed herewith. |
| † | Management contract or compensatory plan or arrangement. |

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# Corporate Information

**Corporate Headquarters**
990 Town and Country Boulevard
Houston, TX 77024-2217

**Marathon Oil Corporation Web Site**
www.marathonoil.com

**Investor Relations Office**
990 Town and Country Boulevard
Houston, TX 77024-2217

Guy Baber, VP Investor Relations
InvestorRelations@marathonoil.com
+1 713-296-1892

**Notice of Annual Meeting**
The 2022 Annual Meeting of Stockholders will be held in person at One MRO, Level 6 Auditorium, 990 Town and Country Boulevard, Houston, TX 77024-2217 on May 25, 2022, 10:00 a.m. Central Time

**Independent Accountants**
PricewaterhouseCoopers LLP
1000 Louisiana Street, Suite 5800
Houston, TX 77002-5021

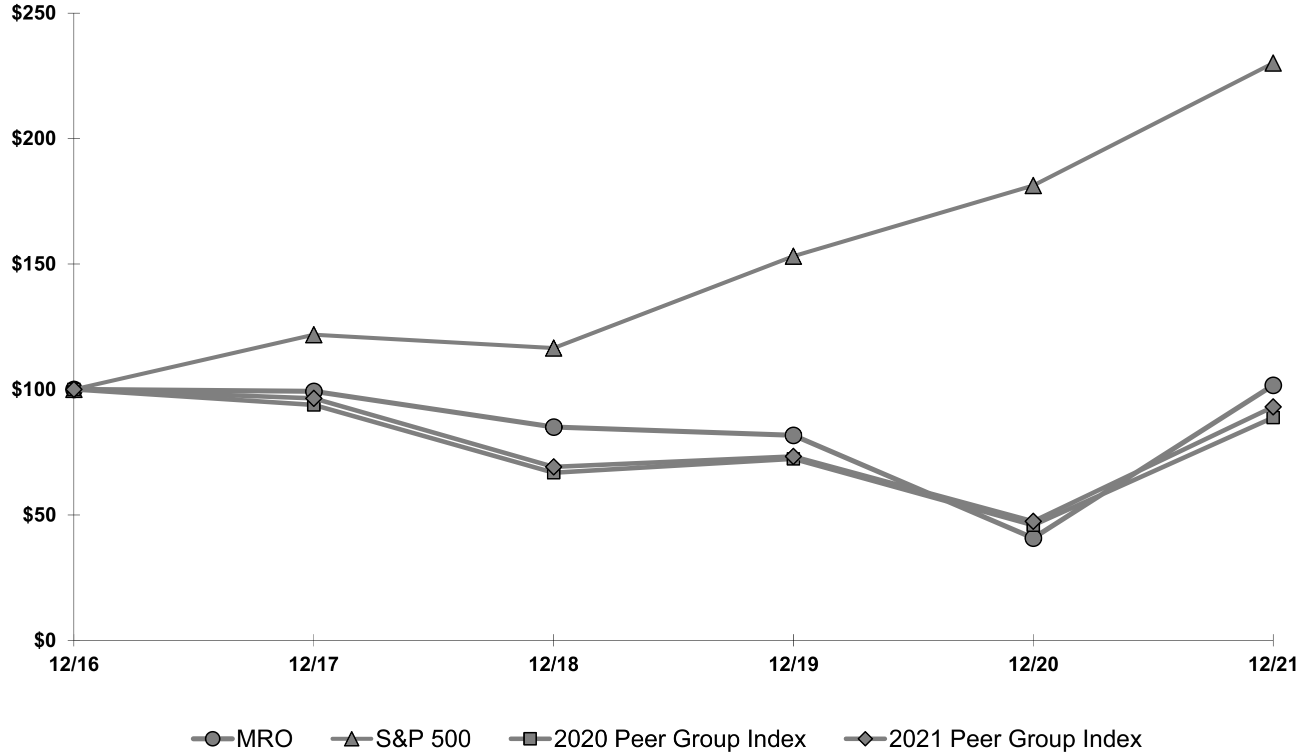
**Stock Exchange Listing**
New York Stock Exchange

**Common Stock Symbol**
MRO

**Stock Transfer Agent**
Computershare
211 Quality Circle, Suite 210
College Station, TX 77845
888-843-5542 (Toll free - U.S., Canada, Puerto Rico)
+1 781-575-4735 (non-U.S.)
web.queries@computershare.com

**Stockholder Return Performance Graph**
The line graph below compares the yearly change in cumulative total stockholder return for our common stock with the cumulative total return of the Standard & Poor's 500 Stock Index ("S&P 500"), the LTI Peer Group Index shown in our 2021 Annual Report, excluding the S&P Energy Index and S&P 500 Index (the "2021 Peer Group Index"), and the Peer Group Index shown in our 2020 Annual Report excluding Chesapeake Energy Corporation, which was removed due to its bankruptcy proceedings (the "2020 Peer Group Index"). We use a Peer Group Index because there is no relevant published industry or line-of-business index that reflects the companies against which we compete as an independent exploration and production company. The 2020 Peer Group Index is comprised of Apache Corporation, Cimarex Energy Co., Continental Resources, Inc., Devon Energy Corporation, EOG Resources, Inc., Hess Corporation, Murphy Oil Corporation, Noble Energy, Inc., Ovintiv Inc. and Pioneer Natural Resources Company. In October 2020, Noble Energy, Inc. was acquired by Chevron Corporation and therefore was included in the 2020 Peer Group Index through the date the acquisition closed. In setting the 2021 Peer Group Index, Diamondback Energy, Inc. was added in order to keep the Peer Group Index a comparable size to prior years. The 2021 Peer Group Index is comprised of Apache Corporation, Cimarex Energy Co., Continental Resources, Inc., Devon Energy Corporation, Diamondback Energy, Inc., EOG Resources, Inc., Hess Corporation, Murphy Oil Corporation, Ovintiv Inc. and Pioneer Natural Resources Company. In October 2021, Cimarex Energy Co. was merged with and into Cabot Oil and Gas Corporation and was therefore included in the 2021 Peer Group Index through the date the acquisition closed.

**Comparison of Cumulative Total Return on $100**
**Invested In Marathon Oil Common Stock on December 31, 2016**
**vs.**
***S&P 500 and Peer Group Index**




***Total return assumes reinvestment of dividends**

# Company Information

**Board of Directors (as of April 1, 2022)**

**Lee M. Tillman**
Chairman, President and CEO, Marathon Oil Corporation

**Chadwick C. Deaton**
Former Executive Chairman, Baker Hughes Incorporated

**Marcela E. Donadio**
Former Partner, Ernst & Young, LLP

**Jason B. Few**
President, CEO and Chief Commercial Officer, FuelCell Energy, Inc.

**M. Elise Hyland**
Former Senior Vice President, EQT Corporation

**Holli C. Ladhani**
Former President and CEO, Select Energy

**Brent J. Smolik**
Former President and COO, Noble Energy, Inc.

**J. Kent Wells**
Former CEO and President, Fidelity Exploration & Production Company and Vice Chairman of MDU Resources

**Executive Officers (as of April 1, 2022)**

**Lee M. Tillman**
Chairman, President and Chief Executive Officer

**Dane E. Whitehead**
Executive Vice President and Chief Financial Officer

**Patrick J. Wagner**
Executive Vice President, Corporate Development and Strategy

**Mike Henderson**
Executive Vice President, Operations

**Kimberly O. Warnica**
Executive Vice President, General Counsel and Secretary

**Rob L. White**
Vice President, Controller and Chief Accounting Officer

**Forward-Looking Statements and Other Items**

This annual report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These are statements, other than statements of historical fact, that give current expectations or forecasts of future events including, without limitation, statements regarding: returns to shareholders (including dividends and share repurchases), capital efficiency, operational execution, per share financial metrics, cash flow, free cash flow, GHG emissions and methane intensity reduction goals, natural gas capture goals and flaring reduction initiatives.

While the Company believes its assumptions concerning future events are reasonable, a number of factors could cause actual results to differ materially from those projected, including, but not limited to: conditions in the oil and gas industry, including supply/demand levels for crude oil and condensate, NGLs and natural gas and the resulting impact on price; changes in expected reserve or production levels; changes in political or economic conditions in the U.S. and Equatorial Guinea, including changes in foreign currency exchange rates, interest rates, inflation rates; actions taken by the members of the Organization of the Petroleum Exporting Countries (OPEC) and Russia affecting the production and pricing of crude oil; and other global and domestic political, economic or diplomatic developments; capital available for exploration and development; risks related to the Company's hedging activities; voluntary or involuntary curtailments, delays or cancellations of certain drilling activities; well production timing; liabilities or corrective actions resulting from litigation, other proceedings and investigations or alleged violations of law or permits; drilling and operating risks; lack of, or disruption in, access to storage capacity, pipelines or other transportation methods; availability of drilling rigs, materials and labor, including the costs associated therewith; difficulty in obtaining necessary approvals and permits; non-performance by third parties of contractual obligations, including due to bankruptcy; the inability of EG LNG to make distributions timely, or at all; unforeseen hazards such as weather conditions, a health pandemic (including COVID-19), acts of war or terrorist acts and the government or military response thereto; security threats, including cybersecurity threats and disruptions to our business and operations from breaches of our information technology systems, or breaches of the information technology systems, facilities and infrastructure of third parties with which we transact business; changes in safety, health, environmental, tax and other regulations, requirements or initiatives, including initiatives addressing the impact of global climate change, air emissions, or water management; other geological, operating and economic considerations; and the risk factors, forward-looking statements and challenges and uncertainties described in the Company's 2021 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and other public filings and press releases, available at https://ir.marathonoil.com/. Except as required by law, the Company undertakes no obligation to revise or update any forward-looking statements as a result of new information, future events or otherwise.

The letter in this annual report includes non-GAAP financial measures, including free cash flow. Reconciliations of the differences between non-GAAP financial measures used in the letter and their most directly comparable GAAP financial measures are available at www.marathonoil.com in the 4Q21 Investor Packet.