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, 2023
or

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

For the transition period from to

Commission File Number 1-1204

Hess Corporation

(Exact name of Registrant as specified in its charter)

DELAWARE	**13-4921002**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification Number)*
1185 AVENUE OF THE AMERICAS, NEW YORK, NY	**10036**
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code (212) 997-8500
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	*Trading Symbol(s)*	*Name of Each Exchange on Which Registered*
Common Stock (par value $1.00)	HES	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 Exchange Act. Yes ☐ No ☑

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

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

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a 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. Yes ☑ No ☐

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

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

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

The aggregate market value of voting stock held by non-affiliates of the Registrant amounted to $37,598,000,000, computed using the outstanding Common Stock and closing market price on June 30, 2023, the last business day of the Registrant's most recently completed second fiscal quarter.

At January 31, 2024, there were 307,152,064 shares of Common Stock outstanding.

Part III is incorporated by reference from the Proxy Statement for the 2024 annual meeting of stockholders.

HESS CORPORATION
Form 10-K
TABLE OF CONTENTS

Unless the context indicates otherwise, references to "Hess", the "Corporation", "Registrant", "we", "us", "our" and "its" refer to the consolidated business operations of Hess Corporation and its subsidiaries.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K, including information incorporated by reference herein, contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Words such as "anticipate," "estimate," "expect," "forecast," "guidance," "could," "may," "should," "would," "believe," "intend," "project," "plan," "predict," "will," "target" and similar expressions identify forward-looking statements, which are not historical in nature. Our forward-looking statements may include, without limitation: our future financial and operational results; our business strategy; estimates of our crude oil and natural gas reserves and levels of production; benchmark prices of crude oil, natural gas liquids and natural gas and our associated realized price differentials; our projected budget and capital and exploratory expenditures; expected timing and completion of our development projects; information about sustainability goals and targets and planned social, safety and environmental policies, programs and initiatives; future economic and market conditions in the oil and gas industry; and expected benefits, timing and completion of the proposed merger with Chevron Corporation (Chevron).

Forward-looking statements are based on our current understanding, assessments, estimates and projections of relevant factors and reasonable assumptions about the future. Forward-looking statements are subject to certain known and unknown risks and uncertainties that could cause actual results to differ materially from our historical experience and our current projections or expectations of future results expressed or implied by these forward-looking statements. The following important factors could cause actual results to differ materially from those in our forward-looking statements:

- fluctuations in market prices of crude oil, natural gas liquids and natural gas and competition in the oil and gas exploration and production industry;
- reduced demand for our products, including due to perceptions regarding the oil and gas industry, competing or alternative energy products and political conditions and events;
- potential failures or delays in increasing oil and gas reserves, including as a result of unsuccessful exploration activity, drilling risks and unforeseen reservoir conditions, and in achieving expected production levels;
- changes in tax, property, contract and other laws, regulations and governmental actions applicable to our business, including legislative and regulatory initiatives regarding environmental concerns, such as measures to limit greenhouse gas emissions and flaring, fracking bans as well as restrictions on oil and gas leases;
- operational changes and expenditures due to climate change and sustainability related initiatives;
- disruption or interruption of our operations due to catastrophic and other events, such as accidents, severe weather, geological events, shortages of skilled labor, cyber-attacks, public health measures, or climate change;
- the ability of our contractual counterparties to satisfy their obligations to us, including the operation of joint ventures under which we may not control and exposure to decommissioning liabilities for divested assets in the event the current or future owners are unable to perform;
- unexpected changes in technical requirements for constructing, modifying or operating exploration and production facilities and/or the inability to timely obtain or maintain necessary permits;
- availability and costs of employees and other personnel, drilling rigs, equipment, supplies and other required services;
- any limitations on our access to capital or increase in our cost of capital, including as a result of limitations on investment in oil and gas activities, rising interest rates or negative outcomes within commodity and financial markets;
- liability resulting from environmental obligations and litigation, including heightened risks associated with being a general partner of Hess Midstream LP;
- risks and uncertainties associated with the proposed Merger (as defined herein) with Chevron, including the following:
  - the risk that regulatory approvals are not obtained or are obtained subject to conditions that are not anticipated by Chevron and Hess;
  - potential delays in consummating the potential transaction, including as a result of regulatory approvals and the request for additional information and documentary material from the Federal Trade Commission;
  - Chevron's ability to integrate Hess' operations in a successful manner and in the expected time period;
  - the possibility that any of the anticipated benefits and projected synergies of the potential transaction will not be realized or will not be realized within the expected time period;
  - the occurrence of any event, change or other circumstance that could give rise to the termination of the Merger Agreement (as defined herein);
  - risks that the anticipated tax treatment of the potential transaction is not obtained, or other unforeseen or unknown liabilities;

  - customer, shareholder, regulatory and other stakeholder approvals and support, or unexpected future capital expenditures;
  - potential litigation relating to the potential transaction that could be instituted against Chevron and Hess or their respective directors, and the possibility that the transaction may be more expensive to complete than anticipated, including as a result of unexpected factors or events;
  - the effect of the announcement, pendency or completion of the potential transaction on the parties' business relationships and business generally, and the risks that the potential transaction disrupts current plans and operations of Chevron or Hess and potential difficulties in Hess employee retention as a result of the transaction, as well as the risk of disruption of Chevron's or Hess' management and business disruption during the pendency of, or following, the potential transaction;
  - the receipt of required Chevron board of directors' authorizations to implement capital allocation strategies, including future dividend payments, and uncertainties as to whether the potential transaction will be consummated on the anticipated timing or at all, or if consummated, will achieve its anticipated economic benefits, including as a result of risks associated with third party contracts containing material consent, anti-assignment, transfer, other provisions that may be related to the potential transaction which are not waived or otherwise satisfactorily resolved, or changes in commodity prices;
  - negative effects of the announcement of the transaction, and the pendency or completion of the proposed acquisition on the market price of Chevron's or Hess' common stock and/or operating results;
  - rating agency actions and Chevron's and Hess' ability to access short and long-term debt markets on a timely and affordable basis; and
- other factors described in Item 1A—Risk Factors in this Annual Report on Form 10-K and any additional risks described in our other filings with the Securities and Exchange Commission.

As and when made, we believe that our forward-looking statements are reasonable. However, given these risks and uncertainties, caution should be taken not to place undue reliance on any such forward-looking statements since such statements speak only as of the date when made and there can be no assurance that such forward-looking statements will occur and actual results may differ materially from those contained in any forward-looking statement we make. Except as required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether because of new information, future events or otherwise.

Glossary

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

API – American Petroleum Institute.

ART Registry – Architecture for REDD+ Transactions Registry.

Appraisal well – An exploration well drilled to confirm the results of a discovery well, or a well that is used to determine the boundaries of a productive formation.

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

Barrel of oil equivalent or boe – This reflects natural gas reserves converted on the basis of relative energy content of six mcf equals one barrel of oil equivalent (one mcf represents one thousand cubic feet). Barrel of oil equivalence does not necessarily result in price equivalence, as the equivalent price of natural gas on a barrel of oil equivalent basis has been substantially lower than the corresponding price for crude oil over the recent past.

Boepd – Barrels of oil equivalent per day.

Bopd – Barrels of oil per day.

CGA – Clean Gulf Associates.

Condensate – A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that when produced, is in the liquid phase at surface pressure and temperature.

DD&A – Depreciation, depletion and amortization.

DEI – Diversity, Equity and Inclusion.

Development well – A well drilled within the proved area of an oil and/or natural gas reservoir with the intent of producing oil and/or natural gas from that area of the reservoir.

Dry hole – An exploratory or development well that does not find oil or natural gas in commercial quantities.

EPA – Environmental Protection Agency.

EHS & SR – Environment, health, safety and social responsibility.

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 by another reservoir.

E&P – Exploration and production.

Field – An area consisting of a single reservoir or multiple reservoirs all grouped or related to the same individual geological structural feature and/or stratigraphic condition.

FPSO – Floating production, storage, and offloading vessel.

Fractionation – A process by which the mixture of natural gas liquids that results from natural gas processing is separated into the NGL components, such as ethane, propane, butane, isobutane, and natural gasoline, prior to their sale to various petrochemical and industrial end users. Fractionation is accomplished by controlling the temperature of the stream of mixed liquids in order to take advantage of the difference in boiling points of separate products.

GAAP – Generally accepted accounting principles in the United States.

GHG – Greenhouse gas.

Gross acres – Acreage in which a working interest is held by the Corporation.

Gross well – A well in which a working interest is held by the Corporation.

ICE – Integrity critical equipment.

IEA – International Energy Agency.

JOA – Joint operating agreement.

LTIP – Long Term Incentive Plans.

Mcf – One thousand cubic feet of natural gas.

Mmcfd – One thousand mcf of natural gas per day.

MSRC – Marine Spill Response Corporation.

MTBE – Methyl tertiary butyl ether.

MWCC – Marine Well Containment Company.

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

NGL or Natural gas liquids – Naturally occurring hydrocarbon substances that are separated and produced by fractionating natural gas, including ethane, butane, isobutane, propane and natural gasoline. NGL do not sell at prices equivalent to crude oil.

NIST CSF – National Institute of Standards and Technology Cybersecurity Framework.

Non-operated – Projects in which the Corporation has a working interest but does not perform the role of Operator.

OPEC – Organization of Petroleum Exporting Countries.

Operator – The entity responsible for conducting and managing exploration, development, and/or production operations for an oil or gas project.

OSHA – Occupational Safety and Health Administration.

OSRL – Oil Spill Response Limited.

Participating interest – Reflects the proportion of exploration and production costs each party will bear as set out in an operating agreement.

Production sharing contract – An agreement between a host government and the owners (or co-owners) of a well or field regarding the percentage of production each party will receive after the parties have recovered a specified amount of capital and operational expenses.

Productive well – A well that is capable of producing hydrocarbons in sufficient quantities to justify commercial exploitation.

Proved properties – Properties with proved reserves.

Proved reserves – In accordance with the Securities and Exchange Commission regulations and practices recognized in the publication of the Society of Petroleum Engineers entitled, *"Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information,"* those quantities of crude oil and condensate, NGL 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 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 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. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

PSU – Performance Share Units.

REDD+ – Reducing Emissions from Deforestation and Forest Degradation.

ROU – Right-of-use.

SOFR – Secured Overnight Financing Rate.

Unproved properties – Properties with no proved reserves.

VLCC – Very large crude carrier.

Working interest – An interest in an oil and gas property that provides the owner of the interest the right to participate in the drilling for and production of oil and gas on the relevant acreage and requires the owner to pay a share of the costs of drilling and production operations.

WWC – Wild Well Control.

PART I

Items 1 and 2. Business and Properties

Hess Corporation, incorporated in the State of Delaware in 1920, is a global E&P company engaged in exploration, development, production, transportation, purchase and sale of crude oil, natural gas liquids, and natural gas with production operations located in the United States (U.S.), Guyana, the Malaysia/Thailand Joint Development Area (JDA) and Malaysia. We conduct exploration activities primarily offshore Guyana, in the U.S. Gulf of Mexico, and offshore Suriname. At the Stabroek Block (Hess 30%), offshore Guyana, we and our partners have discovered a significant resource base and are executing a multi-phased development of the block. We currently have three FPSOs producing, and plan to have six FPSOs with an aggregate expected production capacity of more than 1.2 million gross bopd producing by the end of 2027. The discovered resources to date on the block are expected to underpin the potential for up to ten FPSOs.

Our Midstream operating segment, which includes Hess Corporation's approximate 38% consolidated ownership interest in Hess Midstream LP at December 31, 2023, provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGL; gathering, terminaling, loading and transporting crude oil and NGL; storing and terminaling propane, and water handling services primarily in the Bakken shale play in the Williston Basin area of North Dakota. See *Midstream* on page 13.

On October 22, 2023, we entered into an Agreement and Plan of Merger (the Merger Agreement) with Chevron and Yankee Merger Sub Inc. (Merger Subsidiary), a direct, wholly-owned subsidiary of Chevron. The Merger Agreement provides that, among other things and subject to the terms and conditions of the Merger Agreement, Merger Subsidiary will be merged with and into Hess, and Hess will be the surviving corporation in the Merger as a direct, wholly-owned subsidiary of Chevron (such transaction, the Merger). Under the terms of the Merger Agreement, if the Merger is completed, our stockholders will receive at the effective time of the Merger consideration consisting of 1.025 shares of Chevron common stock for each share of our common stock. The transaction is expected to close mid-2024, subject to shareholder and regulatory approvals and other closing conditions. See *Item 1A. Risk Factors* for a discussion of risks related to the Merger.

Exploration and Production

Proved Reserves

Proved reserves are calculated using the average price during the twelve-month period ending December 31 determined as an unweighted arithmetic average of the price on the first day of each month within the year, unless prices are defined by contractual agreements, and exclude escalations based on future conditions. Crude oil prices used in the determination of proved reserves at December 31, 2023 were $78.10 per barrel for West Texas Intermediate (WTI) (2022: $94.13) and $82.51 per barrel for Brent (2022: $97.98). Our total proved developed and undeveloped reserves at December 31 were as follows:

	Crude Oil & Condensate		Natural Gas Liquids		Natural Gas		Total	
	2023	2022	2023	2022	2023	2022	2023	2022
	(Millions of bbls)		(Millions of bbls)		(Millions of mcf)		(Millions of boe)	
Developed								
United States	**265**	277	**173**	156	**656**	648	**547**	541
Guyana	**201**	116	**—**	—	**71**	37	**213**	122
Malaysia and JDA	**3**	3	**—**	—	**288**	304	**51**	54
	469	396	**173**	156	**1,015**	989	**811**	717
Undeveloped								
United States	**204**	206	**89**	89	**336**	356	**349**	354
Guyana	**186**	164	**—**	—	**114**	54	**205**	173
Malaysia and JDA	**—**	—	**—**	—	**27**	71	**5**	12
	390	370	**89**	89	**477**	481	**559**	539
Total								
United States	**469**	483	**262**	245	**992**	1,004	**896**	895
Guyana	**387**	280	**—**	—	**185**	91	**418**	295
Malaysia and JDA	**3**	3	**—**	—	**315**	375	**56**	66
	859	766	**262**	245	**1,492**	1,470	**1,370**	1,256

Proved undeveloped reserves were 41% of our total proved reserves at December 31, 2023 on a boe basis (2022: 43%). Proved reserves held under production sharing contracts totaled 45% of our crude oil reserves and 34% of our natural gas reserves at December 31, 2023 (2022: 37% and 32%, respectively).

For additional information regarding our proved oil and gas reserves, see the *Supplementary Oil and Gas Data* to the *Consolidated Financial Statements* presented on pages 92 through 101.

Production

Worldwide crude oil, NGL, and natural gas net production was as follows:

	2023	2022	2021
Crude oil – Thousands of barrels			
United States			
North Dakota	**30,271**	27,238	29,176
Offshore	**8,111**	7,995	10,451
Total United States	**38,382**	35,233	39,627
Guyana	**41,831**	28,526	10,920
Malaysia and JDA	**1,728**	1,393	1,264
Other (a)	**—**	5,524	7,791
Total	**81,941**	70,676	59,602
Natural gas liquids – Thousands of barrels			
United States			
North Dakota	**24,634**	19,488	17,889
Offshore	**550**	681	1,517
Total United States	**25,184**	20,169	19,406
Natural gas – Thousands of mcf			
United States			
North Dakota	**69,781**	56,903	59,013
Offshore	**15,565**	16,024	26,276
Total United States	**85,346**	72,927	85,289
Malaysia and JDA	**134,404**	131,509	126,743
Other (a)	**—**	3,565	3,557
Total	**219,750**	208,001	215,589
Total Barrels of Oil Equivalent (in millions) (a)	**143.8**	125.5	114.9

(a) Other includes our interests in Libya (sold in November 2022) and Denmark (sold in August 2021). Net production from Libya was 6.1 million boe for 2022 (2021: 7.2 million boe). Net production from Denmark was 1.2 million boe for 2021.

E&P Operations

At December 31, 2023, our significant E&P assets included the following:

United States

Our production in the U.S. was from the Bakken shale play in the Williston Basin of North Dakota (Bakken) and from offshore properties in the Gulf of Mexico.

North Dakota:

Bakken: At December 31, 2023, we held approximately 466,000 net acres in the Bakken. Net production averaged 182,000 boepd in 2023. We drilled 118 wells and brought 113 wells on production in 2023, bringing the total operated production wells to 1,757 at December 31, 2023. We added a fourth operated rig in July 2022 and during 2024, we plan to operate four rigs.

Offshore:

Gulf of Mexico: At December 31, 2023, we held approximately 44,000 net developed acres, with our production operations principally at the Baldpate (Hess 50%), Conger (Hess 38%), Llano (Hess 50%), Penn State (Hess 50%), Stampede (Hess 25%) and Tubular Bells (Hess 57%) Fields. At December 31, 2023, we held approximately 234,000 net undeveloped acres, of which leases covering approximately 113,000 net acres are due to expire in the next three years. In the fourth quarter of 2023, we were the high bidder on 20 leases in the U.S. Department of Interior's Lease Sale 261 covering approximately 37,000 net acres, and we expect to be awarded these leases in the first quarter of 2024. In 2023, we completed drilling operations on the Hess operated Pickerel-1 exploration well (Hess 100%) located in Mississippi Canyon Block 727, where oil bearing reservoirs were encountered. The well will be a tie-back to the Tubular Bells production facility. We also spud the Hess operated Black Pearl development well (Hess 25%) in the fourth quarter of 2023. The well is planned as a tie-back to the Stampede production facility. In 2024, we plan to participate in two wells.

Guyana

Stabroek Block: The Stabroek Block (Hess 30%), offshore Guyana, covers approximately 6.6 million acres. The operator, ExxonMobil Guyana Ltd, has made more than 30 discoveries since 2015, with the discovered resources to date on the block expected to underpin the potential for up to ten FPSOs. The first six FPSOs are expected to have an aggregate expected production capacity of more than 1.2 million gross bopd by the end of 2027.

The Liza Phase 1 development began producing oil in December 2019 utilizing the Liza Destiny FPSO and in the fourth quarter of 2023 increased its production capacity to within the range of 150,000 gross bopd to 160,000 gross bopd. The Liza Phase 2 development, which commenced producing oil in February 2022 from the Liza Unity FPSO, reached its initial production capacity of approximately 220,000 gross bopd in July 2022, and increased its production capacity to approximately 250,000 gross bopd in the third quarter of 2023. Further production optimization work is planned in 2024. The third development, Payara, began producing oil in November 2023 from the Prosperity FPSO and reached its initial production capacity of approximately 220,000 gross bopd in January 2024.

A fourth development, Yellowtail, was sanctioned in April 2022 and will utilize the ONE GUYANA FPSO with an expected initial production capacity of approximately 250,000 gross bopd, with first production expected in 2025. Six drill centers are planned with up to 26 production wells and 25 injection wells.

A fifth development, Uaru, was sanctioned in April 2023 and will utilize the Errea Wittu FPSO with an expected initial production capacity of approximately 250,000 gross bopd, with first production expected in 2026. Ten drill centers are planned with up to 21 production wells and 23 injection wells.

A sixth development, Whiptail, was submitted to the Government of Guyana for approval in the fourth quarter of 2023. Pending government approvals and project sanctioning, the project is expected to have an initial production capacity of approximately 250,000 gross bopd, with first production anticipated in 2027.

A gas to energy project is underway to construct a 130-mile pipeline network and associated infrastructure in order to transport approximately 50 million standard cubic feet of natural gas per day from the Liza Field to a 300 megawatt onshore power plant (Gas to Energy Project), which is expected to be constructed and operated by the Government of Guyana. ExxonMobil Guyana Ltd. expects to complete pipeline construction and field hook-up by the end of 2024.

The expiration of the exploration license for the Stabroek Block was extended one year from October 2026 to October 2027, and the end of the first renewal period of the exploration license, which requires the relinquishment of 20% of the acreage not held by discoveries, was extended one year from October 2023 to October 2024, both as a result of force majeure due to the COVID-19 pandemic.

In 2023, the operator drilled a total of three successful exploration and appraisal wells that encountered oil and two unsuccessful exploration wells for which the well costs were expensed. Subsequent to December 31, 2023, the operator completed one successful exploration well and one successful appraisal well. In 2024, the operator plans to utilize six drillships to continue to perform exploration, appraisal, and development activities.

Kaieteur Block: We relinquished our 20% participating interest, subject to government approval, in the Kaieteur Block which is adjacent to the Stabroek Block, in the third quarter of 2023.

Malaysia and JDA

Malaysia/Thailand Joint Development Area (JDA): Production comes from the Carigali Hess operated Block A-18 in the Malaysia/Thailand joint development area in the Gulf of Thailand (Hess 50%). In 2024, the operator plans to drill approximately five development wells.

Malaysia: Our production in Malaysia comes from our interests in Block PM302 (Hess 50%) and Block PM325 (Hess 50%) located in the North Malay Basin (NMB), offshore Peninsular Malaysia and Block PM301 (Hess 50%), which is adjacent to and is unitized with Block A-18 of the JDA. In 2024, we plan to continue development activities at NMB, including drilling approximately five wells.

Other

Suriname: We hold a 33% non-operated participating interest in both Block 42 and Block 59, offshore Suriname. Exploration activities are planned at both blocks in 2024.

Canada: We held a 25% non-operated participating interest in two exploration licenses offshore Newfoundland, which expired in January 2024. In 2023, the operator, BP Canada, completed drilling operations on the Ephesus exploration well which did not encounter commercial quantities of hydrocarbons.

Sales Commitments

We have certain long-term contracts with fixed minimum sales volume commitments for natural gas and NGL production. At the JDA in the Gulf of Thailand, we have annual minimum net sales commitments of approximately 70 billion cubic feet of natural gas per year through 2025 and approximately 30 billion cubic feet per year in 2026 and 2027. At the North Malay Basin development project, offshore Peninsular Malaysia, we have annual minimum net sales commitments of approximately 55 billion cubic feet of natural gas per year through 2025. At the Liza Phase 1 and Phase 2 development projects at the Stabroek Block, offshore Guyana, we have annual minimum net sales commitments of approximately 2.6 billion cubic feet of natural gas per year following the commissioning period of the Gas to Energy Project. ExxonMobil Guyana Ltd. expects to complete pipeline construction and field hook-up by the end of 2024. The estimated total volume of natural gas subject to these sales commitments is approximately 375 billion cubic feet. We also have multiple minimum delivery commitments in the Bakken for natural gas and NGL with various end dates through 2032, with total commitments of approximately 120 million boe over the remaining life of the contracts.

We have not experienced any significant constraints in satisfying the committed quantities required by our sales commitments, and we anticipate being able to meet future requirements from available proved and probable reserves, as well as projected third-party supply in the case of NGL.

Selling Prices and Production Costs

The following table presents our average selling prices and average production costs:

	2023	2022	2021
Average Selling Prices (a)			
Crude Oil – Per Barrel (Including Hedging)			
United States			
North Dakota	**$ 70.44**	$ 81.06	$ 55.57
Offshore	**72.06**	81.38	60.09
Total United States	**70.80**	81.14	56.64
Guyana	**80.72**	89.86	68.57
Malaysia and JDA	**75.51**	89.77	71.00
Other (b)	**—**	93.67	66.39
Worldwide	**75.97**	85.76	60.08
Crude Oil – Per Barrel (Excluding Hedging)			
United States			
North Dakota	**$ 73.80**	$ 91.26	$ 59.90
Offshore	**75.39**	91.51	64.77
Total United States	**74.15**	91.32	61.05
Guyana	**82.20**	96.52	71.07
Malaysia and JDA	**75.51**	89.77	71.00
Other (b)	**—**	101.92	69.25
Worldwide	**78.29**	94.15	63.90
Natural Gas Liquids – Per Barrel			
United States			
North Dakota	**$ 20.77**	$ 35.09	$ 30.74
Offshore	**20.87**	35.24	26.40
Worldwide	**20.77**	35.09	30.40
Natural Gas – Per Mcf			
United States			
North Dakota	**$ 1.68**	$ 5.50	$ 4.08
Offshore	**2.16**	6.21	3.25
Total United States	**1.76**	5.66	3.82
Malaysia and JDA	**5.95**	5.62	5.15
Other (b)	**—**	5.93	3.40
Worldwide	**4.32**	5.64	4.60
Average production (lifting) costs per barrel of oil equivalent produced (c)			
United States			
North Dakota (d)	**$ 27.16**	$ 29.02	$ 25.87
Offshore	**26.98**	22.19	12.88
Total United States	**27.61**	28.16	23.27
Guyana (e)	**9.60**	11.23	17.93
Malaysia and JDA	**7.33**	6.12	4.72
Other (b)	**—**	2.78	6.34
Worldwide	**18.96**	18.97	17.91

(a) Selling prices in the United States and Guyana are adjusted for certain processing and distribution fees included in Marketing expenses.
(b) Other includes our interests in Libya (sold in November 2022) and Denmark (sold in August 2021).
(c) Production (lifting) costs consist of amounts incurred to operate and maintain our producing oil and gas wells, related equipment and facilities and transportation costs, including Midstream tariff expense. Lifting costs do not include costs of finding and developing proved oil and gas reserves, production and severance taxes, or the costs of related general and administrative expenses, interest expense and income taxes.
(d) Includes Midstream tariff expense of $18.73 per boe in 2023 (2022: $21.21 per boe; 2021: $19.23 per boe).
(e) Includes pre-development costs from the operator for future phases of development and Hess internal costs totaling $1.87 per boe in 2023 (2022: $2.76 per boe; 2021: $5.76 per boe).

Gross and Net Undeveloped Acreage

At December 31, 2023, gross and net undeveloped acreage amounted to:

	Undeveloped Acreage (a)	
	Gross	Net
	(In thousands)	
United States	340	235
Guyana	9,804	2,608
Malaysia and JDA	197	98
Canada	1,304	326
Suriname	4,363	1,454
Total (b)	16,008	4,721

(a) Includes acreage held under production sharing contracts.
(b) At December 31, 2023, 63% of our net undeveloped acreage, primarily in Suriname, Guyana, and Canada is scheduled to expire during the next three years pending results of exploration activities.

Gross and Net Developed Acreage, and Productive Wells

At December 31, 2023 gross and net developed acreage and productive wells amounted to:

	Developed Acreage Applicable to Productive Wells		Productive Wells (a)			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
	(In thousands)					
United States	794	511	3,266	1,572	10	5
Guyana	164	49	31	9	—	—
Malaysia and JDA	481	241	—	—	134	65
Total	1,439	801	3,297	1,581	144	70

(a) Includes multiple completion wells (wells producing from different formations in the same bore hole) totaling 31 gross wells and 27 net wells.

Exploratory and Development Wells

Net exploratory and net development wells completed during the years ended December 31 were:

	Net Exploratory Wells			Net Development Wells		
	2023	2022	2021	2023	2022	2021
Productive wells						
United States	**1**	—	—	**105**	70	48
Guyana	**1**	3	3	**5**	2	3
Malaysia and JDA	—	1	—	**8**	6	2
Libya	—	—	—	—	—	1
	2	4	3	**118**	78	54
Dry holes						
United States	—	—	—	—	—	—
Guyana (a)	**1**	—	—	—	—	—
Canada (b)	—	—	—	—	—	—
	1	—	—	—	—	—
Total	**3**	4	3	**118**	78	54

(a) Includes the Fish/Tarpon-1 and Kokwari-1 wells in 2023, the Banjo-1 well in 2022, and the Koebi-1 well in 2021 at the Stabroek Block.
(b) Includes the Ephesus well offshore Newfoundland in 2023.

Number of Wells in the Process of Being Drilled

At December 31, 2023, the number of wells in the process of drilling amounted to:

	Gross Wells	Net Wells
United States	57	18
Guyana (a)	22	7
Malaysia and JDA	4	2
Total	83	27

(a) Includes 12 gross (and 4 net) water injection and gas injection wells in process at December 31, 2023.

Midstream

Prior to December 16, 2019, the Midstream segment was primarily comprised of Hess Infrastructure Partners LP (HIP), a 50/50 joint venture between Hess Corporation and Global Infrastructure Partners (GIP), formed to own, operate, develop and acquire a diverse set of midstream assets to provide fee-based services to Hess and third-party customers. HIP was initially formed on May 21, 2015, with Hess selling 50% of HIP to GIP for approximately $2.6 billion on July 1, 2015.

On April 10, 2017, HIP completed an initial public offering (IPO) of 16,997,000 common units, representing 30.5% limited partnership interests in its subsidiary Hess Midstream Partners LP (Hess Midstream Partners), for net proceeds of approximately $365.5 million. In connection with the IPO, HIP contributed a 20% controlling economic interest in each of Hess North Dakota Pipeline Operations LP, Hess TGP Operations LP, and Hess North Dakota Export Logistics Operations LP, and a 100% economic interest in Hess Mentor Storage Holdings LLC (collectively the “Contributed Businesses”). In exchange for the Contributed Businesses, Hess and GIP each received common and subordinated units representing a direct 33.75% limited partner interest in Hess Midstream Partners and a 50% indirect ownership interest through HIP in Hess Midstream Partners’ general partner, which had a 2% economic interest in Hess Midstream Partners plus incentive distribution rights.

On December 16, 2019, Hess Midstream Partners acquired HIP, including HIP’s 80% interest in Hess Midstream Partners’ oil and gas midstream assets, HIP’s water services business and the outstanding economic general partner interest and incentive distribution rights in Hess Midstream Partners. In addition, Hess Midstream Partners’ organizational structure converted from a master limited partnership into an “Up-C” structure in which Hess Midstream Partners’ public unitholders received newly issued Class A shares in a new public entity named Hess Midstream LP (Hess Midstream), which is taxed as a corporation for U.S. federal and state income tax purposes. Hess Midstream Partners changed its name to “Hess Midstream Operations LP” (HESM Opco) and became a consolidated subsidiary of Hess Midstream, the new publicly listed entity. As consideration for the acquisition, Hess received a cash payment of $301 million and approximately 115 million newly issued HESM Opco Class B units. After giving effect to the acquisition and related transactions, public shareholders of Class A shares in Hess Midstream owned 6% of the consolidated entity on an as-exchanged basis and Hess and GIP each owned 47% of the consolidated entity on an as-exchanged basis, primarily through the sponsors’ ownership of Class B units in HESM Opco that are exchangeable into Class A shares of Hess Midstream on a one-for-one basis.

In 2021, Hess Midstream completed two underwritten public equity offerings of an aggregate of approximately 15.5 million Hess Midstream Class A shares held by affiliates of Hess and GIP. The Class A shares of Hess Midstream were obtained by Hess and GIP through the exchange of 15.5 million of their Class B units of HESM Opco. In 2021, HESM Opco repurchased 31.25 million HESM Opco Class B units held by affiliates of Hess and GIP for $750 million in a single transaction. HESM Opco issued $750 million in aggregate principal amount of 4.250% fixed-rate senior unsecured notes due 2030 in a private offering to finance the repurchase.

In 2022, Hess Midstream completed a single underwritten public equity offering of approximately 10.2 million Hess Midstream Class A shares held by affiliates of Hess and GIP. The Class A shares of Hess Midstream were obtained by Hess and GIP through the exchange of approximately 10.2 million of their Class B units of HESM Opco. In 2022, HESM Opco repurchased approximately 13.6 million HESM Opco Class B units held by affiliates of Hess and GIP for $400 million in a single transaction. HESM Opco issued $400 million in aggregate principal amount of 5.500% fixed-rate senior unsecured notes due 2030 in a private offering to repay borrowings under its revolving credit facility used to finance the repurchase.

In 2023, Hess Midstream completed two underwritten public equity offerings of an aggregate of approximately 24.3 million Hess Midstream Class A shares held by affiliates of Hess and GIP. The Class A shares of Hess Midstream were obtained by Hess and GIP through the exchange of 24.3 million of their Class B units of HESM Opco. In 2023, HESM Opco repurchased an aggregate of approximately 13.6 million HESM Opco Class B units in multiple transactions from affiliates of Hess and GIP for total proceeds of $400 million. The unit repurchases were financed by borrowings under HESM Opco's revolving credit facility.

After giving effect to the above transactions, public shareholders of Class A shares of Hess Midstream own approximately 30%, GIP owns approximately 32%, and Hess owns approximately 38% of the consolidated entity on an as-exchanged basis at December 31, 2023.

At December 31, 2023, Midstream assets included the following:

- *Natural Gas Gathering and Compression:* A natural gas gathering and compression system located primarily in McKenzie, Williams and Mountrail Counties, North Dakota connecting Hess and third-party owned or operated wells to the Tioga Gas Plant, Little Missouri 4 Gas Plant, and third-party pipeline facilities. This gathering system consists of approximately 1,410 miles of high and low pressure natural gas and NGL gathering pipelines with a current capacity of up to approximately 660 mmcfd. The system has an aggregate compression capacity of approximately 480 mmcfd including approximately 70 mmcfd of compression capacity added in 2023 by constructing one new greenfield compressor station and expanding an existing compressor station. Construction was also completed on an additional greenfield compressor station that, once put into operation in early 2024, will further increase compression capacity by approximately 30 mmcfd.
- *Crude Oil Gathering:* A crude oil gathering system located primarily in McKenzie, Williams and Mountrail Counties, North Dakota, connecting Hess and third-party owned or operated wells to the Ramberg Terminal Facility, the Tioga Rail Terminal and the Johnson's Corner Header System. The crude oil gathering system consists of approximately 570 miles of crude oil gathering pipelines with a current capacity of up to approximately 290,000 bopd.
- *Tioga Gas Plant:* A natural gas processing and fractionation plant located in Tioga, North Dakota, with a current total processing capacity of approximately 400 mmcfd, an NGL fractionation capacity of approximately 60,000 boepd and y-grade NGL stabilization capacity of approximately 25,000 boepd.
- *Little Missouri 4:* A natural gas processing plant in McKenzie County, North Dakota, with processing capacity of approximately 200 mmcfd, which was placed in service during 2019 and is operated by Targa Resources Corp. Hess Midstream LP owns a 50% interest in Little Missouri 4 through a joint venture with Targa Resources Corp. and is entitled to half of the plant's processing capacity.
- *Mentor Storage Terminal:* A propane storage cavern and rail and truck loading and unloading facility located in Mentor, Minnesota, with approximately 330,000 boe of working storage capacity.
- *Ramberg Terminal Facility:* A crude oil pipeline and truck receipt terminal located in Williams County, North Dakota with a delivery capacity of up to approximately 285,000 bopd of crude oil into an interconnecting pipeline for transportation to the Tioga Rail Terminal, Dakota Access Pipeline (DAPL) and other third-party pipelines and storage facilities.
- *Tioga Rail Terminal:* A 140,000 bopd crude oil and 30,000 boepd NGL rail loading terminal in Tioga, North Dakota that is connected to the Tioga Gas Plant, the Ramberg Terminal Facility and our crude oil gathering system.
- *Crude Oil Rail Cars:* A total of 550 crude oil rail cars, which are operated as unit trains consisting of approximately 100 to 110 crude oil rail cars. These crude oil rail cars have been constructed to DOT-117 standards.
- *Johnson's Corner Header System:* A crude oil pipeline header system located in McKenzie County, North Dakota that receives crude oil by pipeline from Hess and third parties and delivers crude oil to DAPL and other third-party interstate pipeline systems. The facility has a delivery capacity of approximately 100,000 bopd of crude oil.
- *Produced Water Gathering and Disposal:* A produced water gathering system located primarily in Williams and Mountrail Counties, North Dakota, that transports produced water from the wellsite by approximately 300 miles of pipeline in gathering systems or by third-party trucking to water handling facilities for disposal.
- *Other DAPL Connections:* Various connections into DAPL, which are crude oil delivery points within the terminal system located in Williams and Mountrail Counties, North Dakota that receive crude oil by pipeline from the crude oil gathering system for delivery into DAPL. The facility has a delivery capacity of approximately 120,000 bopd of crude oil.

The Midstream segment earns substantially all of its revenues by charging fees for gathering, compressing and processing natural gas and fractionating NGLs; gathering, terminaling, loading and transporting crude oil and NGLs; storing and terminaling propane; and gathering and disposing produced water. Effective January 1, 2014, certain subsidiaries of Hess Midstream entered into (i) gas gathering, (ii) crude oil gathering, (iii) gas processing and fractionation, (iv) storage services and (v) terminaling and export services commercial agreements with certain subsidiaries of Hess, each generally with an initial ten-year term which could be extended for an additional ten-year term at the unilateral right of the Hess Midstream subsidiaries. The Hess Midstream subsidiaries exercised their right to extend the terms of each of these commercial agreements for the secondary term effective January 1, 2024 through December 31, 2033. Effective January 1, 2019, a subsidiary of Hess Midstream entered into water gathering and disposal services agreements with a subsidiary of Hess. These agreements also provide Hess Midstream the capacity to provide concurrent use of these services directly to third parties.

The commercial agreements contain minimum volume commitments which are based on nominations covering substantially all of the E&P segment's existing and future owned or controlled production in the Bakken and projected third-party volumes owned or controlled by the E&P segment through dedicated third-party contracts. Minimum volume commitments are equal to 80% of the nominations and apply on a three-year rolling basis such that they are set for the three years following the most recent nomination. During the initial term of each commercial agreement, volume deficiencies are measured quarterly and any associated shortfall payments are not subject to future reduction or offset. During the secondary term of each commercial agreement, the applicable Hess subsidiary will be entitled to receive a credit with respect to the amount of any shortfall fee paid. Such Hess subsidiary may apply the credit against the fees payable for any volumes delivered under the applicable agreement in excess of the nominated volumes up to four quarters after the credit is earned. No credits will be provided with respect to crude oil terminaling services under the terminaling and export services commercial agreement or water handling services under the water gathering and disposal services agreements.

Competition and Market Conditions

See *Item 1A. Risk Factors* for a discussion of competition and market conditions.

Emergency Preparedness and Response Plans and Procedures

We have in place a series of business and asset-specific emergency preparedness, response and business continuity plans that detail procedures for rapid and effective emergency response and environmental mitigation activities. These plans are maintained, reviewed and updated as necessary to confirm their accuracy and suitability. Where applicable, they are also reviewed and approved by the relevant host government authorities.

Responder training and drills are routinely held worldwide to assess and continually improve the effectiveness of our plans. Our contractors, service providers, representatives from government agencies and, where applicable, joint venture partners participate in the drills to help ensure that emergency procedures are comprehensive and can be effectively implemented.

To complement internal capabilities and to help ensure coverage for our global operations, we maintain membership contracts with a network of local, regional and global oil spill response and emergency response organizations. At the regional and global level, these organizations include CGA, MSRC, MWCC, WWC and OSRL. CGA and MSRC are domestic spill response organizations and MWCC provides the equipment and personnel to contain underwater well control incidents in the Gulf of Mexico. WWC provides firefighting, well control and engineering services globally. OSRL is a global response organization and is available, when needed, to assist us with any of our assets. In addition to owning response assets in their own right, the organization maintains business relationships that provide immediate access to additional critical response support services if required. OSRL's response assets include nearly 300 recovery and storage vessels and barges, more than 250 skimmers, over 600,000 feet of boom, nine capping stacks and significant quantities of dispersants and other ancillary equipment, including aircraft. In addition to external well control and oil spill response support, we have contracts with wildlife, environmental, meteorology, incident management, medical and security resources. If we were to engage these organizations to obtain additional critical response support services, we would fund such services and, where appropriate, seek reimbursement under our insurance coverage, as described below. In certain circumstances, we pursue and enter into mutual aid agreements with other companies and government cooperatives to receive and provide oil spill response equipment and personnel support. We maintain close associations with emergency response organizations through our representation on the Executive Committee and Response Network Committee of MWCC, the Technical Operations Committee of CGA and the Emergency Preparedness and Response Committee of API. We also maintain regular voting membership in CGA, MSRC and OSRL.

We continue to participate in several industry-wide task forces that are studying better ways to assess the risk of and prevent onshore and offshore incidents, access and control blowouts in subsea environments, and improve containment and recovery methods. The task forces are working closely with the oil and gas industry and international government agencies to implement improvements and increase the effectiveness of oil spill prevention, preparedness, response and recovery processes.

Insurance Coverage and Indemnification

We maintain insurance coverage that includes coverage for physical damage to our property, third-party liability, workers' compensation and employers' liability, general liability, sudden and accidental pollution and other coverage. This insurance coverage is subject to deductibles, exclusions and limitations and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

The amount of insurance covering physical damage to our property and liability related to negative environmental effects resulting from a sudden and accidental pollution event, excluding windstorm coverage for which we are self-insured, varies by asset, based on the asset's estimated replacement value or the estimated maximum loss. In the case of a catastrophic event, first party coverage consists of two tiers of insurance. The first $450 million of coverage is provided through an industry mutual insurance group. Above this $450 million threshold, additional insurance is carried which ranges in value up to $800 million in total at December 31, 2023, depending on the asset coverage level, as described above. The insurance programs covering physical damage to our property exclude business interruption protection for our E&P operations. Additionally, we carry insurance that provides third-party coverage for general liability, and sudden and accidental pollution, up to $830 million, which coverage under a standard JOA would be reduced to our participating interest. Our insurance policies renew at various dates each year. Future insurance coverage could increase in cost and may include higher deductibles or retentions, or additional exclusions or limitations. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are deemed economically acceptable.

Generally, our drilling contracts (and most of our other offshore services contracts) provide for a mutual hold harmless indemnity structure whereby each party to the contract (the Corporation and contractor) indemnifies the other party for injuries or damages to their personnel and property (and, often, those of its contractors/subcontractors) regardless of fault. Variations may include indemnity exclusions to the extent a claim is attributable to the gross negligence and/or willful misconduct of a party. Third-party claims, on the other hand, are generally allocated on a fault basis.

We are customarily responsible for, and indemnify the contractor against, all claims including those from third parties, to the extent attributable to pollution or contamination by substances originating from our reservoirs or other property and the contractor is responsible for and indemnifies us for all claims attributable to pollution emanating from the contractor's property. Variations may include indemnity exclusions to the extent a claim is attributable to the gross negligence and/or willful misconduct of a party. Additionally, we are generally liable for all of our own losses and most third-party claims associated with catastrophic losses such as damage to reservoirs, blowouts, cratering and loss of hole, regardless of cause, although exceptions for losses attributable to gross negligence and/or willful misconduct do exist. Lastly, some offshore services contracts include overall limitations of the contractor's liability equal to a fixed negotiated amount. Variations may include exclusions of all contractual indemnities from the liability cap.

Under a standard JOA, each party is liable for all claims arising under the JOA, to the extent of its participating interest (operator or non-operator). Variations include indemnity exclusions when the claim is based upon the gross negligence and/or willful misconduct of the operator, in which case the operator is solely liable. The parties to the JOA may continue to be jointly and severally liable for claims made by third parties in some jurisdictions. Further, under some production sharing contracts between a governmental entity and commercial parties, liability of the commercial parties to the government entity is joint and several.

Government Regulations

The crude oil and natural gas industry is regulated at federal, state, local and foreign government levels. Regulations affecting elements of the energy sector are under continuous review for amendment or expansion over time, which may result in incremental costs of doing business and affect our profitability. See *Regulatory, Legal and Environmental Risks* in *Item 1A. Risk Factors*. Compliance with various existing environmental, health and safety regulations is not expected to have a material adverse effect on our financial condition or results of operations. However, increasingly stringent environmental regulations have resulted and will likely continue to result in higher capital expenditures and operating expenses for us and the oil and gas industry in general and may reduce demand for our products. We spent approximately $28 million in 2023 (2022: $23 million; 2021: $16 million) for environmental remediation. Additionally, we may be exposed to decommissioning liabilities, including for divested assets. See *Note 8, Asset Retirement Obligations* in the *Notes to Consolidated Financial Statements.* The level of other expenditures to comply with federal, state, local and foreign country regulations is difficult to quantify as such costs are captured as mostly indistinguishable components of our capital expenditures and operating expenses. For further discussion of environmental, health and safety regulations affecting our business, see *Environment, Health and Safety* in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Human Capital Management

Corporate Culture and Overview

Our human capital strategy aims to attract, engage and retain our talent by investing in their professional development and providing them with challenging and rewarding opportunities for personal growth. Our workplace culture is guided by our values and reinforced by developing quality leadership, fostering DEI, emphasizing continuous learning, creating opportunities for engagement, driving innovation, and embracing Lean improvement processes. We utilize the Life at Hess framework to optimize the work experience for our multigenerational and demographically diverse workforce and unlock the discretionary effort that is required to perform at a high level on a sustained basis. The Life at Hess framework encompasses programs, policies and practices, and a listening system that draws on in-person dialogues, pulse polls and data analytics to help leaders understand employees' experiences and perspectives to inform their decision making.

As of December 31, 2023, we had 1,756 employees globally, as detailed below.

	United States	Guyana	Malaysia and JDA	Total
Job Category				
Executives and Senior Officers	29	—	1	30
First and Mid-Level Managers	373	—	67	440
Professionals	815	—	90	905
Other	377	—	4	381
Total	**1,594**	**—**	**162**	**1,756**

Life at Hess

We prioritize the safety of our workforce with programs and practices designed to help ensure that everyone, everywhere gets home safe every day. We continue to adapt our work policies and benefits to prioritize emotional, mental and physical health and well-being.

During 2023, we held several employee surveys throughout the year to understand employee sentiment and engagement and made the following improvements in response to employee feedback:

- formalized individual and team learning paths with new in-person and virtual learning and mentoring opportunities;
- enhanced resources to improve the effectiveness of hybrid working;
- enhanced our wellness program supporting physical, financial, social and emotional well-being of our employees; and
- established a new training and development program to help leaders navigate an increasingly dynamic, diverse, and complex work environment.

Diversity, Equity and Inclusion

In keeping with our values and purpose, we have a longstanding commitment to DEI and taking action to foster a sustainable culture of inclusion for everyone. DEI is a business imperative for improved performance and the innovation needed to accomplish our business goals now and in the future. Additionally, Hess is committed to providing a global workplace free from discrimination and harassment, where everyone can achieve their full potential. We provide equal employment opportunities for all employees and job candidates regardless of race, color, religion, gender, age, sexual orientation, gender identity, creed, national origin, genetic information, disability, veteran status or any other protected status.

Hess' DEI Council provides executive leadership guidance to embed DEI into our culture and drive progress throughout the organization. Our expectations for a culture fostering mutual respect and trust are included in our Code of Business Conduct and Ethics and related policies. It is also reinforced regularly with employees at every level through regular communication and ongoing training. Additional information about our policies and practices, including training, employee engagement initiatives and workforce data, is included in our sustainability reports and annual U.S. Equal Employment Opportunity reporting, which is available on our website at www.hess.com.

During 2023, Hess either maintained or improved diversity across most levels of our workforce, as illustrated in the table below. We believe our strategic focus on DEI, including new training and diversity outreach programs and our inaugural Hess Inclusion Summit, contributed to this outcome. Our DEI leader helps to develop a tailored, long-term strategy that defines our objectives and strategies to advance DEI now and in the future. We have six employee resource groups that provide valuable employee insights to sustain a diverse, equitable and inclusive environment for everyone to thrive and perform at their best and partner with outside organizations to improve DEI in our communities. Each year, we share workforce activity and trends such as employee turnover, promotions, DEI and development metrics, along with qualitative information such as program development and progress, with our Board of Directors. Management also reviews these topics in greater detail with the Compensation and Management Development Committee throughout the year.

	Women (U.S. and International)			Minorities (a) (U.S. Based Employees)		
	2023	**2022**	**2021**	**2023**	**2022**	**2021**
Job Category						
Executives and Senior Officers	**17 %**	16 %	16 %	**20 %**	19 %	19 %
First and Mid-Level Managers	**24 %**	23 %	23 %	**22 %**	22 %	20 %
Professionals	**33 %**	33 %	34 %	**32 %**	31 %	30 %
Other	**17 %**	18 %	19 %	**16 %**	16 %	16 %
Total	**27 %**	27 %	27 %	**26 %**	25 %	24 %

(a) As defined by the U.S. Department of Labor.

Compensation and Benefits Programs

Our compensation and benefits programs are focused on attracting and retaining a highly skilled workforce in a rapidly changing industry. We benchmark these programs each year against other companies in our industry and conduct a review to help foster pay equity. The results are shared in our sustainability reports and on www.hess.com. We maintain an annual incentive plan that applies to all employees, including executive officers, with shared enterprise performance metrics for all participants. We also provide a comprehensive, nationally recognized wellness program that is designed to improve the physical, financial, social and emotional well-being of our employees.

Information about our Executive Officers

The following table presents information as of February 26, 2024 regarding executive officers of the Corporation:

Name	Age	Office Held* and Business Experience	Year Individual Became an Executive Officer
John B. Hess	69	*Chief Executive Officer and Director* Mr. Hess has been Chief Executive Officer of the Corporation since 1995 and employed by the Corporation since 1977. He has over 45 years of experience in the oil and gas industry.	1983
Gregory P. Hill	62	*President and Chief Operating Officer* Mr. Hill has been Chief Operating Officer since 2014 and President of the Corporation's worldwide Exploration and Production business since joining the Corporation in January 2009. Prior to joining the Corporation, Mr. Hill spent 25 years at Royal Dutch Shell and its affiliates in a variety of operations, engineering, technical and managerial roles in Asia-Pacific, Europe and the United States.	2009
Timothy B. Goodell	66	*Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer* Mr. Goodell has been General Counsel of the Corporation since 2009, Corporate Secretary since 2016, Chief Compliance Officer since 2017 and Executive Vice President since 2020. Prior to joining the Corporation in 2009, he was a partner at the law firm of White & Case, LLP where he spent 25 years.	2009
John P. Rielly	61	*Executive Vice President and Chief Financial Officer* Mr. Rielly has been Chief Financial Officer of the Corporation since 2004 and Executive Vice President since 2020. Mr. Rielly previously served as Vice President and Controller of the Corporation from 2001 to 2004. Prior to joining the Corporation in 2001, he was a Partner at Ernst & Young, LLP where he was employed for 17 years.	2002
Richard Lynch	66	*Senior Vice President, Technology and Services* Mr. Lynch has been Senior Vice President, Technology and Services of the Corporation since 2018. Mr. Lynch previously was Senior Vice President Global Developments, Drilling and Completions from 2014. Prior to joining the Corporation in 2014, Mr. Lynch spent over 30 years in well delivery and operations, as well as project and asset management, with BP plc and ARCO.	2018
Gerbert Schoonman	58	*Senior Vice President, Global Production* Mr. Schoonman has been Senior Vice President, Global Production of the Corporation since January 2020. Since joining the Company in 2011, he served in various operational leadership roles, including as Vice President, Production – Asia Pacific, from January 2011 through August 2012; Vice President, Onshore – Bakken from September 2012 through December 2016; and most recently, as Vice President, Offshore since January 2017. Prior to joining the Corporation, he spent 20 years with Royal Dutch Shell where he served in operational and leadership roles.	2020
Andrew Slentz	62	*Senior Vice President, Human Resources and Office Management* Mr. Slentz has been Senior Vice President, Human Resources of the Corporation since April 2016 and responsible for Office Management since 2018. Prior to joining the Corporation in 2016, Mr. Slentz served as Executive Vice President of Administration and Human Resources at Peabody Energy since 2010. Mr. Slentz has over 30 years in human resources experience at large international public companies.	2016
Barbara Lowery-Yilmaz	67	*Senior Vice President and Chief Exploration Officer* Ms. Lowery-Yilmaz has been the Senior Vice President, Exploration of the Corporation since 2014 and Chief Exploration Officer since 2020. Ms. Lowery-Yilmaz has over 30 years of oil and gas industry experience in exploration and technology with BP plc and its affiliates including senior leadership roles.	2014

* *All officers referred to herein hold office in accordance with our By-laws until the first meeting of directors in connection with the annual meeting of stockholders of the Corporation and until their successors shall have been duly chosen and qualified. Each of said officers was elected to the office opposite their name on May 17, 2023.*

Each of the above officers has been employed by the Corporation or its affiliates in various managerial and executive capacities for more than five years.

Access to Our Reports

We make available free of charge through our website, www.hess.com, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission. The information on our website, including our sustainability report, is not part of or otherwise incorporated by reference in this report. Our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and the charters for the Audit Committee, Compensation and Management Development Committee, Corporate Governance and Nominating Committee and Environmental, Health and Safety Committee of the Board of Directors are available on our website and are also available free of charge upon request to Investor Relations at our principal executive office. We also file with the New York Stock Exchange (NYSE) an annual certification by our Chief Executive Officer regarding our compliance with the NYSE's corporate governance standards.

Item 1A. Risk Factors

Our business activities and the value of our securities are subject to significant risks, including the risk factors described below. These risk factors could negatively affect our operations, financial condition, liquidity and results of operations, and as a result, holders and purchasers of our securities could lose part or all of their investments. It is possible that additional risks relating to our securities may be described in a prospectus supplement if we issue securities in the future.

Proposed Chevron Merger Risks

We will be subject to business uncertainties while the Merger is pending, which could adversely affect our businesses. Uncertainty about the effect of the Merger on employees and those that do business with us may have an adverse effect to the Corporation. These uncertainties may impair our ability to attract, retain and motivate key personnel until the Merger is completed and for a period of time thereafter, and could cause those that transact with us to seek to change their existing business relationships with us. Employee retention at the Corporation may be challenging during the pendency of the Merger, as employees may experience uncertainty about their roles. In addition, the Merger Agreement restricts us from entering into certain corporate transactions, entering into certain material contracts, making certain changes to our capital budget, incurring certain indebtedness and taking other specified actions without the consent of Chevron, and generally requires us to continue our operations in the ordinary course of business during the pendency of the Merger. These restrictions may prevent us from pursuing attractive business opportunities or adjusting our capital plan prior to the completion of the Merger.

We may become subject to lawsuits relating to the Merger, which could adversely affect our business, financial condition and operating results. We and/or our respective directors and officers may become subject to lawsuits relating to the Merger. Such litigation is very common in connection with acquisitions of public companies, regardless of the merits of the underlying acquisition. While we will evaluate and defend against any actions vigorously, the costs of the defense of such lawsuits and other effects of such litigation could have an adverse effect on our business, financial condition and operating results.

Completion of the Merger is subject to a number of conditions, and if these conditions are not satisfied or waived, the Merger will not be completed. Failure to complete, or significant delays in completing, the Merger could negatively affect the trading prices of our common stock and our future business and financial results. Completion of the Merger is subject to satisfaction or waiver of certain closing conditions, including (i) the receipt of the required approval from our stockholders, (ii) the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended applicable to the Merger, (iii) the absence of any order or law prohibiting consummation of the Merger, (iv) the effectiveness of the Registration Statement on Form S-4 to be filed by Chevron pursuant to which the shares of Chevron common stock to be issued in connection with the Merger will be registered with the U.S. Securities and Exchange Commission and (v) the authorization for listing on the New York Stock Exchange of the shares of Chevron common stock to be issued in connection with the Merger. The obligation of each party to consummate the Merger is also conditioned upon the other party having performed in all material respects its obligations under the Merger Agreement and the other party's representations and warranties in the Merger Agreement being true and correct (subject to certain materiality qualifiers). Additionally, Hess and Chevron have been engaged in discussions with Exxon Mobil Corporation and China National Offshore Oil Corporation regarding a right of first refusal provision in the joint operating agreement for the Stabroek Block. If these discussions do not result in an acceptable resolution and arbitration (if pursued) does not result in a confirmation that such right of first refusal provision is inapplicable to the Merger, then there would be a failure of a closing condition under the Merger Agreement, in which case the Merger would not close. For additional information, please see the section entitled "The Merger-Stabroek JOA" in Chevron's preliminary registration statement on Form S-4 to be filed on February 26, 2024. The obligation of Hess to consummate the merger is also subject to the receipt of a tax opinion from legal counsel that the Merger will qualify as a "reorganization" within the meaning of Section 368(a) of the Internal Revenue Code of 1986, as amended. There can be no assurance that the conditions to the completion of the Merger will be satisfied or waived or that the Merger will be completed.

If the Merger is not completed, or if there are significant delays in completing the Merger, the trading prices of our common stock and our future business and financial results could be negatively affected, and we may be subject to several risks, including the following:

- the requirement that we pay Chevron a termination fee of approximately $1.715 billion under certain circumstances provided in the Merger Agreement;
- negative reactions from the financial markets, including declines in the prices of our common stock due to the fact that current prices may reflect a market assumption that the Merger will be completed;
- having to pay certain significant costs relating to the Merger; and
- the attention of our management will have been diverted to the Merger rather than our own operations and pursuit of other opportunities that could have been beneficial to us.

The Merger Agreement limits our ability to pursue alternatives to the Merger. The Merger Agreement contains provisions that may discourage a third party from submitting a competing proposal that might result in greater value to our stockholders than the Merger, or may result in a potential competing acquirer of the Corporation proposing to pay a lower per share price to acquire us than it might otherwise have proposed to pay. These provisions include a general prohibition on us from soliciting or, subject to certain exceptions relating to the exercise of fiduciary duties by our board of directors, entering into discussions with any third party regarding any competing proposal or offer for a competing transaction.

Because the exchange ratio in the Merger Agreement is fixed and because the market price of Chevron common stock will fluctuate prior to the completion of the Merger, our stockholders cannot be sure of the market value of the Chevron common stock they will receive as consideration in the Merger. Under the terms of the Merger Agreement, if the Merger is completed, our stockholders will receive at the effective time of the Merger consideration consisting of 1.025 shares of Chevron common stock for each share of our common stock. The exchange ratio of the Merger consideration is fixed, and under the Merger Agreement there will be no adjustment to the Merger consideration for changes in the market price of Chevron common stock or our common stock prior to the completion of the Merger.

If the Merger is completed, there will be a time lapse between the date of signing of the Merger Agreement and the date on which our stockholders who are entitled to receive the Merger consideration actually receive the Merger consideration. The respective market values of Chevron common stock and our common stock have fluctuated and may continue to fluctuate during this period as a result of a variety of factors, including general market and economic conditions, changes in each company's business, operations and prospects, commodity prices, regulatory considerations, and the market's assessment of Chevron's business and the Merger. Such factors are difficult to predict and in many cases may be beyond the control of Chevron and us. The actual value of the Merger consideration received by our stockholders at the completion of the Merger will depend on the market value of Chevron common stock at that time. This market value may differ, possibly materially, from the market value of Chevron common stock at the time the Merger Agreement was entered into or at any other time.

Shares of Chevron common stock received by our stockholders as a result of the Merger will have different rights from shares of our common stock. Upon completion of the Merger, our stockholders will no longer be stockholders of Hess, and our stockholders who receive the Merger consideration will become Chevron stockholders, and their rights as Chevron stockholders will be governed by the terms of Chevron's charter and by-laws. There are differences between the current rights of our stockholders and the rights to which such stockholders will be entitled as Chevron stockholders.

Market and Third-Party Risks

Our business and operating results are highly dependent on the market prices of crude oil, NGL and natural gas, which can be very volatile. Our estimated proved reserves, revenue, operating cash flows, operating margins, liquidity, financial condition and future earnings are highly dependent on the benchmark market prices of crude oil, NGL and natural gas, and our associated realized price differentials, which are volatile and influenced by numerous factors beyond our control. The major foreign oil producing countries, including members of OPEC, may exert considerable influence over the supply and price of crude oil and refined petroleum products. Their ability to agree on a common policy on rates of production and other matters may have a significant impact on the oil markets. Other factors include, but are not limited to: worldwide and domestic supplies of and demand for crude oil, NGL and natural gas; political conditions and events (including weather, instability, changes in governments, armed conflict, economic sanctions and outbreaks of infectious diseases, such as COVID-19) around the world and in particular in crude oil or natural gas producing regions; the cost of exploring for, developing and producing crude oil, NGL and natural gas; the price, availability of and demand for alternative fuels or other forms of energy; the effect of energy conservation and environmental protection efforts; and overall economic conditions globally (including inflation, slower growth or recession, higher interest rates, supply chain constraints, and consequences associated with the ongoing invasion of Ukraine by Russia or the conflict between Israel and Hamas). The sentiment of commodities trading markets as well as other supply and demand factors may also influence the selling prices of crude oil, NGL and natural gas. Average benchmark prices for 2023 were $77.60 per barrel for WTI (2022: $94.33; 2021: $68.08) and $82.18 per barrel for Brent (2022: $99.04; 2021: $70.95). In order to manage the potential volatility of cash flows and credit requirements, we maintain significant bank credit facilities. An inability to access, renew or replace such credit facilities or access other sources of funding as they mature would negatively impact our liquidity. Furthermore, from time to time we have entered into, and may in the future enter into or modify, commodity price hedging arrangements to manage commodity price volatility. These arrangements may limit potential upside from commodity price increases, or expose us to additional risks, such as counterparty credit risk, which could adversely impact our cash flow, liquidity or financial condition.

We do not always control decisions made under joint operating agreements and the parties under such agreements may fail to meet their obligations. We conduct many of our E&P operations through joint operating agreements with other parties under which we may not control decisions, either because we do not have a controlling interest or are not operator under the agreement. There is risk that these parties may at any time have economic, business, or legal interests or goals that are inconsistent with ours, and therefore decisions may be made which are not what we believe is in our best interest. Moreover, parties to these agreements may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone. For example, in June 2021, the U.S. Bankruptcy Court approved the bankruptcy plan for Fieldwood Energy LLC which includes transferring abandonment obligations of Fieldwood to us and other predecessors in title of certain of its assets, who are jointly and severally liable for the obligations. See *Note 8, Asset Retirement Obligations* in the *Notes to Consolidated Financial Statements*. As a result, actions of our contractual counterparties may adversely affect the value of our investments and result in increased costs or liabilities.

Our industry is highly competitive and many of our competitors are larger and have greater resources and more diverse portfolios than we have. The petroleum industry is highly competitive and very capital intensive. We encounter competition from numerous companies, including acquiring rights to explore for crude oil and natural gas. To a lesser extent, we are also in competition with producers of alternative fuels or other forms of energy, including wind, solar and electric power, and in the future, could face increasing competition due to the development and adoption of new technologies. Many competitors, including national oil companies, are larger and have substantially greater resources to acquire and develop oil and gas assets, or may have established strategic relationships in areas we operate, or may be willing to incur a higher level of risk than we are willing to incur. In addition, competition for drilling services, technical expertise and equipment may affect the availability of technical personnel and drilling rigs, resulting in increased capital and operating costs. Many of our competitors have a more diverse portfolio of assets, which may minimize the impact of adverse events occurring at any one location.

Operational and Strategic Risks

If we fail to successfully increase our reserves, our future crude oil and natural gas production will be adversely impacted. We own or have access to a finite amount of oil and gas reserves, which will be depleted over time. Replacement of oil and gas production and reserves, including proved undeveloped reserves, is subject to successful exploration drilling, development activities, and enhanced recovery programs. Therefore, future oil and gas production is dependent on technical success in finding and developing additional hydrocarbon reserves. Exploration activity involves the interpretation of seismic and other geological and geophysical data, which does not always successfully predict the presence of commercial quantities of hydrocarbons. Drilling risks include unexpected adverse conditions, irregularities in pressure or formations, equipment failure, blowouts and weather interruptions. Future developments may be affected by unforeseen reservoir conditions, which negatively affect recovery factors or flow rates. Similar risks may be encountered in the production of oil and gas on properties acquired from others. In addition, replacing reserves and developing future production are also influenced by the price of crude oil and natural gas and costs of drilling and development activities. Lower crude oil and natural gas prices may reduce capital available for our exploration and development activities, render certain development projects uneconomic or delay their completion, and result in negative revisions to existing reserves while increasing drilling and development costs could negatively affect expected economic returns.

There are inherent uncertainties in estimating quantities of proved reserves and discounted future net cash flows, and actual quantities may be lower than estimated. Numerous uncertainties exist in estimating quantities of proved reserves and future net revenues from those reserves. Actual future production, oil and gas prices, revenues, taxes, capital expenditures, operating expenses, and quantities of recoverable oil and gas reserves may vary substantially from those assumed in the estimates and could materially affect the estimated quantities of our proved reserves and the related future net revenues. In addition, reserve estimates may be subject to downward or upward changes based on production performance, purchases or sales of properties, results of future development, changes in prevailing oil and gas prices, production sharing contracts, which may decrease reserves as crude oil and natural gas prices increase, and other factors.

Catastrophic and other events, whether naturally occurring or man-made, may materially affect our operations and financial condition. Our oil and gas operations are subject to numerous risks and hazards inherent to operating in the crude oil and natural gas industry, including catastrophic events, which may damage or destroy assets, interrupt operations, result in personal injury and have other significant adverse effects. These events include unexpected drilling conditions, pressure conditions or irregularities in reservoir formations, equipment malfunctions or failures, derailments, fires, explosions, blowouts, oil releases, power outages, cratering, pipeline interruptions and ruptures, severe weather, such as hurricanes, floods, freezes and heat waves or droughts, geological events, shortages in availability of skilled labor, cyber-attacks or health measures related to outbreaks of infectious diseases, such as COVID-19. We maintain insurance coverage against many, but not all, potential losses and liabilities in amounts we deem prudent, including for property and casualty losses. Some forms of insurance may be unavailable in the future or be available only on terms that are deemed economically unacceptable. Moreover, there can be no assurance that such insurance will adequately protect us against liability from all potential consequences and damages. For example, we are self-insured against physical damage to property and liability related to windstorms. In 2023 and 2022, there was no significant hurricane-related downtime whereas in 2021, hurricane related downtime reduced net production by 4,000 boepd and hurricane related maintenance and repair costs were approximately $7 million. In addition, the frequency and severity of weather conditions and other meteorological phenomena, including storms, droughts, extreme temperatures, and changes in temperature and precipitation patterns that impact our business activities, may also be impacted by the effects of climate change. Energy needs could increase or decrease as a result of extreme weather conditions depending on the duration and magnitude of any such climate change. Increased energy use due to weather changes may require us to invest in order to serve increased demand or create operational challenges. A decrease in energy use due to weather changes may affect our financial condition through decreased revenues. To the extent the frequency of extreme weather events increases, this could adversely impact our business, results of operations and financial condition.

Significant time delays between the estimated and actual occurrence of critical events associated with development projects may result in material negative economic consequences. As part of our business, we are involved in large development projects, the completion of which may be delayed beyond what was originally planned. Such examples include, but are not limited to, delays in receiving necessary approvals from project members or regulatory or other government agencies, timely access to necessary equipment, services or resources, availability of necessary personnel, construction delays, unfavorable weather conditions, equipment failures, and outbreaks of infectious diseases, such as COVID-19. These delays could impact our future results of operations and cash flows.

An inability to secure personnel, drilling rigs, equipment, supplies and other required services or to retain key employees may result in material negative economic consequences. We are dependent on oilfield service companies for items including drilling rigs, equipment, supplies and skilled labor. The availability and cost of drilling rigs, equipment, supplies and skilled labor will fluctuate over time given the cyclical nature of the E&P industry. Concerns over global economic conditions, inflation, supply chain disruptions, labor shortages, and other factors, each of which are beyond our control, contribute to increased economic uncertainty for us and our suppliers. As a result, we may encounter difficulties in obtaining required services or could face an increase in cost, which may impact our ability to run our operations and deliver projects on time with the potential for material negative economic consequences. In addition, difficulty in recruiting and retaining adequate numbers of experienced technical personnel could negatively impact our ability to deliver on our strategic goals. Our future success also depends upon the continued service of key members of our senior management team, who play an important role in developing and implementing our strategy. An inability to recruit and retain adequate numbers of experienced technical and professional personnel in the necessary locations or the loss or departure of key members of senior management may prevent us from executing our strategy in full or in part, which could negatively impact our business.

Disruption, failure or cybersecurity attacks affecting or targeting information technology and infrastructure used by the Corporation or our business partners may materially impact our business and operations. Computers and telecommunication systems are an integral part of our exploration, development and production activities and the activities of our business partners. We rely on computer systems, hardware, software, technology infrastructure and online sites and networks for both internal and external operations that are critical to our business (collectively, Digital Systems). Some of our Digital Systems are managed and owned by us, but we rely on third parties for a range of Digital Systems and related products and services, including but not limited to cloud computing services. We use these Digital Systems to communicate, analyze and store proprietary, financial and operating data as well as data about employees, business partners and other third parties (collectively, Confidential Information). Our reliance on technology has increased due to our use of remote communications and hybrid work-from-home arrangements, which increase cybersecurity risks due to the challenges associated with managing remote computing assets and security vulnerabilities that are present in many non-corporate and home networks.

Technical system flaws, power loss and cybersecurity risks, including cyber or phishing-attacks, unauthorized access, malicious software, data privacy breaches by employees or others with authorized access, ransomware, and other cybersecurity issues, could compromise our Digital Systems or those of our business partners and result in disruptions to our business operations or the access, disclosure or loss of our Confidential Information and communications. In addition, computers control oil and gas production, processing equipment, and distribution systems globally and are necessary to deliver our production to market. A disruption, failure or a cyber breach of these operating systems, or of the networks and infrastructure on which they rely, could damage critical production, distribution and/or storage assets, delay or prevent delivery to markets, and make it difficult or impossible to accurately account for production and settle transactions. As a result, any such disruption, failure or cyber breach and any resulting investigation or remediation costs, reputational harm, litigation or regulatory action could have a material adverse impact on our cash flows and results of operations, reputation and competitiveness.

We routinely experience attempts by external parties to penetrate and attack our Digital Systems. Although such attempts to date have not resulted in any material breaches, disruptions, financial loss, or loss of business-critical information, our systems and procedures for protecting against such attacks and mitigating such risks may prove to be insufficient in the future. Threat actors are becoming increasingly adept in using techniques and tools, including artificial intelligence, that circumvent security controls, evade detection and remove forensic evidence. As technologies evolve and these cybersecurity attacks become more sophisticated, we may incur significant costs to upgrade or enhance our security measures to protect against such attacks. We may also face difficulties in fully anticipating or implementing adequate preventive measures or mitigating potential harm.

Financial Risks

We have substantial capital requirements, and we may not be able to obtain needed financing on satisfactory terms. The exploration, development and production of crude oil and natural gas involve substantial costs, which may not be fully funded from operations. All three major credit rating agencies that rate our debt have assigned an investment grade rating. Although currently we do not have any borrowings under our long-term credit facility, a ratings downgrade, rising interest rates, continued weakness in the oil and gas industry or negative outcomes within commodity and financial markets could adversely impact our access to capital markets by increasing the costs of financing, or by impacting our ability to obtain financing on satisfactory terms. In addition, a ratings downgrade may require that we issue letters of credit or provide other forms of collateral under certain contractual requirements. Environmental concerns and other factors have led to lower oil and gas representation in certain key equity market indices and may increase our costs to access the equity capital markets. Any inability to access capital markets could adversely impact our financial adaptability and our ability to execute our strategy.

We may engage in risk management transactions designed to mitigate commodity price volatility and other risks that may impede our ability to benefit from commodity price increases and can expose us to similar potential counterparty credit risk as amounts due from the sale of hydrocarbons. We may enter into commodity price hedging arrangements to protect us from commodity price declines. These arrangements may, depending on the instruments used and the level of additional hedges involved, limit any potential upside from commodity price increases. As with accounts receivable from the sale of hydrocarbons, we may be exposed to potential economic loss should a counterparty be unable or unwilling to perform their obligations under the terms of a hedging agreement. In addition, we are exposed to risks related to changes in interest rates and foreign currency values, and may engage in hedging activities to mitigate related volatility.

Regulatory, Legal and Environmental Risks

Our oil and gas operations are subject to environmental risks and environmental, health and safety laws and regulations that can result in significant costs and liabilities. Our oil and gas operations are subject to environmental risks such as oil spills, produced water spills, gas leaks and ruptures and discharges of substances or gases that could expose us to substantial liability for pollution or other environmental damage. Our operations are also subject to numerous U.S. federal, state, local and foreign environmental, health and safety laws and regulations. Non-compliance with these laws and regulations may subject us to administrative, civil or criminal penalties, remedial clean-ups, natural resource damages and other liabilities. In addition, increasingly stringent environmental regulations have resulted and will likely continue to result in higher capital expenditures and operating expenses for us. Similarly, we have material legal obligations to dismantle, remove and abandon production facilities and wells that will occur many years in the future, in most cases. These estimates may be impacted by future changes in regulations, solvency of subsequent owners and partners and other uncertainties.

Concerns have been raised in certain jurisdictions where we have operations concerning the safety and environmental impact of the drilling and development of shale oil and gas resources, particularly hydraulic fracturing, water usage, flaring of associated natural gas and air emissions. While we believe that these operations can be conducted safely and with minimal impact on the environment, regulatory bodies are responding to these concerns and may impose moratoriums and new regulations on such drilling operations that would likely have the effect of prohibiting or delaying such operations and increasing their cost.

Climate change, sustainability and other ESG initiatives may result in significant operational changes and expenditures, reduced demand for our products and adversely affect our business. We recognize that climate change and sustainability is a growing global environmental concern. Continuing political and social attention to the issue of climate change and sustainability has resulted in both existing and pending international agreements and national, regional or local legislation and regulatory measures to limit GHG emissions. These agreements and measures may require, or could result in future legislation and regulatory measures that require, significant equipment modifications, operational changes, taxes, or purchase of emission credits to reduce emission of GHGs from our operations, which may result in substantial capital expenditures and compliance, operating, maintenance and remediation costs. For example, the Inflation Reduction Act of 2022 (IRA) includes a methane emissions reduction program for petroleum and natural gas systems, which requires the EPA to impose a "waste emissions charge" on excess methane emissions from certain natural gas and oil sources that are required to report under EPA's Greenhouse Gas Reporting Program beginning January 1, 2024 and also provides significant funding and incentives for research and development of competing low carbon energy production methods. California recently enacted three climate-related disclosure laws, the Climate Corporate Data Accountability Act, Climate Related Financial Risk Act and Voluntary Carbon Market Disclosures Act, which together will require certain entities doing business in California or taking certain actions in California to report and attain third-party assurance of greenhouse gas emissions information, reporting on climate-related financial risks and reporting regarding the use of voluntary carbon credits and/or carbon reduction claims. Legislation similar to California's Climate Corporate Data Accountability Act is under consideration in other states. In addition to increased costs for compliance, such legislation, regulations and initiatives could also impact demand as our production is sold to third parties that produce petroleum fuels, which through normal end user consumption result in the emission of GHGs.

We are prioritizing sustainable energy practices to further reduce our carbon footprint while at the same time remaining a successful operating public company. However, various key stakeholders, including our stockholders, employees, suppliers, customers, local communities and others, may have differing approaches to climate change initiatives. If we do not successfully manage expectations across these varied stakeholder interests, it could erode our stakeholders' trust and thereby affect our reputation. Shareholder activism has been recently increasing in our industry, and stockholders may attempt to effect changes to our business or governance, whether by shareholder proposals, public campaigns, proxy solicitations or otherwise. In addition, certain financial institutions, institutional investors and other sources of capital have begun to limit or eliminate their investment in oil and gas activities due to concerns about climate change, which could make it more difficult to finance our business. We continue to focus on developing our ESG practices, and as voluntary and regulatory ESG disclosure standards and policies continue to evolve, we have expanded and expect to further expand our public disclosures in these areas. Such disclosures may reflect aspirational goals, targets, cost estimates and other expectations and assumptions, including over long timelines, which aspirational goals, targets, cost estimates, and other expectations and assumptions are necessarily uncertain and may not be realized. Failure to realize or timely achieve progress on such aspirational goals, targets, cost estimates, and other expectations or assumptions may adversely impact us.

Furthermore, as a result of heightened public awareness and attention to climate change and sustainability as well as continued regulatory initiatives to reduce the use of petroleum fuels, demand for crude oil and other hydrocarbons may be reduced, which may have an adverse effect on our sales volumes, revenues and margins. The imposition and enforcement of stringent GHG emissions reduction requirements could severely and adversely impact the oil and gas industry and therefore significantly reduce the value of our business. Increasing attention to climate change risks and sustainability has resulted in governmental investigations, and public and private litigation, which could increase our costs or otherwise adversely affect our business. For example, beginning in 2017, certain states, municipalities and private associations in California, Delaware, Maryland, Rhode Island and South Carolina separately filed lawsuits against oil, gas and coal producers, including us, for alleged damages purportedly caused by climate change. Such actions could adversely impact our business by distracting management and other personnel from their primary responsibilities, require us to incur increased costs, and/or result in reputational harm.

We are subject to changing laws and regulations and other governmental actions that can significantly and adversely affect our business. Political or regulatory developments and governmental actions, including federal, state, local, territorial and foreign laws and regulations may adversely affect our operations and those of our counterparties with whom we have contracted, which may affect our financial results. These actions could result in tax increases retroactively through tax claims or prospectively through changes to applicable statutory tax rates, modification of the tax base, or imposition of new tax types. For example, on August 16, 2022 the U.S. enacted the IRA, which includes a 15% book-income alternative minimum tax on corporations with average adjusted financial statement income over $1 billion for any 3-year period ending with 2022 or later and a 1% excise tax on the fair market value of stock that is repurchased by publicly traded U.S. corporations. The alternative minimum tax and the excise tax are effective in taxable years beginning after December 31, 2022. From time to time since enactment, the Department of Treasury and the Internal Revenue Service have issued interim guidance related to the alternative minimum tax and intend to issue proposed regulations addressing the alternative minimum tax in the future. We continue to evaluate the effect of the new law and any additional guidance on our future cash flows and financial results, including if we become a taxpayer subject to the alternative minimum tax, which would apply to any taxable years beginning on or after January 1, 2024. The impact of the excise tax provision will be dependent on the extent of share repurchases made in future periods. We continue to evaluate the corporate alternative minimum tax and its potential impact on our future U.S. tax expense, cash taxes, and effective tax rate, as well as any other impacts the IRA may have on our financial position and results of operations.

Additionally, governmental actions could include limitations on post-production deductions from royalty payments; limitations or prohibitions on the sales of new oil and gas leases or extensions on existing oil and gas leases; adverse court decisions with respect to the sale of new and existing oil and gas leases or claims related to working interest payments; expropriation or nationalization of property; mandatory government participation, cancellation or amendment of contract rights; imposition of capital controls or blocking of funds; changes in import and export regulations; the imposition of tariffs; and anti-bribery or anti-corruption laws. In recent years, proposals for limitations on access to oil and gas exploration and development opportunities and related litigation have grown in certain areas and may include efforts to reduce access to public and private lands; restriction of exploration and production activities within government-owned and other lands; delaying or canceling permits for drilling or pipeline construction; restrictions or changes to existing pipeline easements; limiting or banning industry techniques such as hydraulic fracturing and/or adding restrictions on the use of water and associated disposal; imposition of set-backs on oil and gas sites; reduction of sulfur content in bunker fuel; delaying or denying air-quality or siting permits; advocating for increased regulations, punitive taxation, or citizen ballot initiatives or moratoriums on industry activity; and the use of social media channels to cause reputational harm. Costs associated with responding to these anti-development efforts or complying with any new legal or regulatory requirements could significantly and adversely affect our business, financial condition and results of operations.

Political instability globally and in areas where we operate can adversely affect our business. Political instability and civil unrest have affected and may continue to affect the oil and gas markets generally. Some international areas are politically less stable than other areas and may be subject to civil unrest, conflict, insurgency, corruption, security risks and labor unrest. Political instability in areas where we operate may expose our operations to increased risks, including increased difficulty in obtaining required permits and government approvals, enforcing our agreements in those jurisdictions and potential adverse actions by local government authorities. The invasion of Ukraine by Russia in February 2022 has led to disruption, instability, and volatility in global markets and industries, including the oil and gas markets. The U.S. government and other foreign governments imposed severe economic sanctions and export controls against Russia, certain regions of Ukraine and particular entities and individuals, and may impose additional sanctions and controls. The recent war between Israel and Hamas, which began in October 2023, has the potential for further disruption of economic markets, particularly if the conflict expands to other parts of the Middle East. To date, we have not experienced a material impact to operations or the consolidated financial statements as a result of these conflicts; however, we will continue to monitor for events that could materially impact us or our industry. Furthermore, the threat of terrorism around the world also poses additional risks to our operations and the operations of the oil and gas industry in general. In addition, geographic territorial border disputes may affect our business in certain areas, such as the border dispute between Guyana and Venezuela over a portion of the Stabroek Block.

One of our subsidiaries is the general partner of a publicly traded limited partnership, Hess Midstream LP. The responsibilities associated with being a general partner expose us to a broader range of legal liabilities. Our control of Hess Midstream LP bestows upon us additional duties and obligations including, but not limited to, the obligations associated with managing potential conflicts of interests and additional reporting requirements from the Securities and Exchange Commission. These heightened duties expose us to additional potential for legal claims that may have a material negative economic impact on our stockholders. Moreover, these increased duties may lead to an increase in compliance costs.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Cybersecurity Risk Management and Strategy

Cybersecurity is an integral part of our enterprise risk management. We have developed and implemented a cybersecurity risk management program intended to protect the confidentiality, integrity and availability of our Digital Systems. Our cybersecurity risk management program includes a cybersecurity incident response plan as well as property and casualty insurance that may cover damages caused as a result of a cybersecurity event.

We design and assess our program based on the NIST CSF. This does not imply that we meet any particular technical standards, specifications, or requirements, only that we use the NIST CSF as a guide to help us identify, assess and manage cybersecurity risks relevant to our business.

Our cybersecurity risk management program is integrated into our overall enterprise risk management program overseen by our Chief Risk Officer, and shares certain methodologies, reporting channels and governance processes that apply across the enterprise risk management program to other areas affecting our business risks, including financial, compliance, EHS, compensation and governance matters, among other topics.

Our cybersecurity risk management program includes:

- risk assessments designed to help identify material cybersecurity risks to critical systems integral to our exploration, development and production activities as well as the activities of our business partners and our broader enterprise information technology environment;
- a security team principally responsible for managing our cybersecurity risk assessment processes, our security controls and our response to cybersecurity incidents;
- the use of external service providers, where appropriate, to assess, test or otherwise assist with aspects of our security controls;
- ongoing cybersecurity awareness and compliance training that occurs quarterly and is mandatory for all our employees, incident response personnel and senior management;
- a cybersecurity incident response plan that includes procedures for responding to cybersecurity incidents; and
- a third-party risk management process for service providers, suppliers and vendors.

We have not identified risks from known cybersecurity threats during the year ended December 31, 2023, including as a result of any prior cybersecurity incidents, that have materially affected us or are reasonably likely to materially affect us, including our operations, business strategy, results of operations, or financial condition.

Additional information about cybersecurity risks we face is discussed in *Item 1A. Risk Factors*, under the heading "*Disruption, failure or cybersecurity attacks affecting or targeting information technology and infrastructure used by the Corporation or our business partners may materially impact our business and operations*" which should be read in conjunction with the information above.

Governance

Our Board of Directors (Board) appreciates the rapidly evolving nature of threats presented by cybersecurity incidents and is committed to the prevention, timely detection and mitigation of the effects of any such incidents on the Corporation. The Board considers cybersecurity risk as part of its risk oversight function and has delegated to the Audit Committee (Committee) primary responsibility for oversight of our risk management practices, including oversight of cybersecurity and other information technology risks.

The Committee oversees management's implementation of our cybersecurity risk management program. The Committee receives presentations on cybersecurity topics from management at least twice a year, including the nature of threats, defense and detection capabilities; incident response plans; and employee training activities. In addition, management updates the Committee, as necessary, regarding any material cybersecurity incidents as well as other incidents with lesser impact potential. The Committee reports to the full Board regarding its activities, including those related to cybersecurity.

Our management team – including our Chief Risk Officer, our Head of Information Technology and our Chief Information Security Officer (CISO) – is responsible for assessing and managing our material risks from cybersecurity threats. The team is primarily responsible for our overall cybersecurity risk management program and supervises both our internal cybersecurity personnel and our retained external cybersecurity consultants. Our Chief Risk Officer has nearly 20 years of experience in this role at the Corporation and previously served as a consultant with Ernst & Young LLP's Risk Management and Regulatory Practice, where he assisted financial services and energy trading clients in establishing their risk management infrastructure. Our Head of Information Technology and our CISO each have over 20 years of experience in information technology leadership in oil and gas. Furthermore, our CISO holds a Bachelor of Science in Cyber and Data Security from the University of Arizona and is a Certified Information Systems Security Professional.

Our management team is informed about and monitors the efforts to prevent, detect, mitigate and remediate cybersecurity risks and incidents through various means, which may include briefings from internal security personnel; threat intelligence and other information obtained from governmental, public or private sources, including external consultants engaged by us; and alerts and reports produced by security tools deployed in the information technology environment.

Item 3. Legal Proceedings

Information regarding legal proceedings is contained in *Note 17, Guarantees, Contingencies and Commitments* in the *Notes to Consolidated Financial Statements* and is incorporated herein by reference. Pursuant to Item 103(c)(3)(iii) of Regulation S-K under the Exchange Act, we are required to disclose certain information about environmental proceedings to which a governmental authority is a party if we reasonably believe such proceedings may result in monetary sanctions, exclusive of interest and costs, above a stated threshold. We have elected to apply a threshold of $1 million for purposes of determining whether disclosure of any such proceedings is required.

Item 4. Mine Safety Disclosures

None.

PART II

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

Stock Market Information, Holders and Dividends

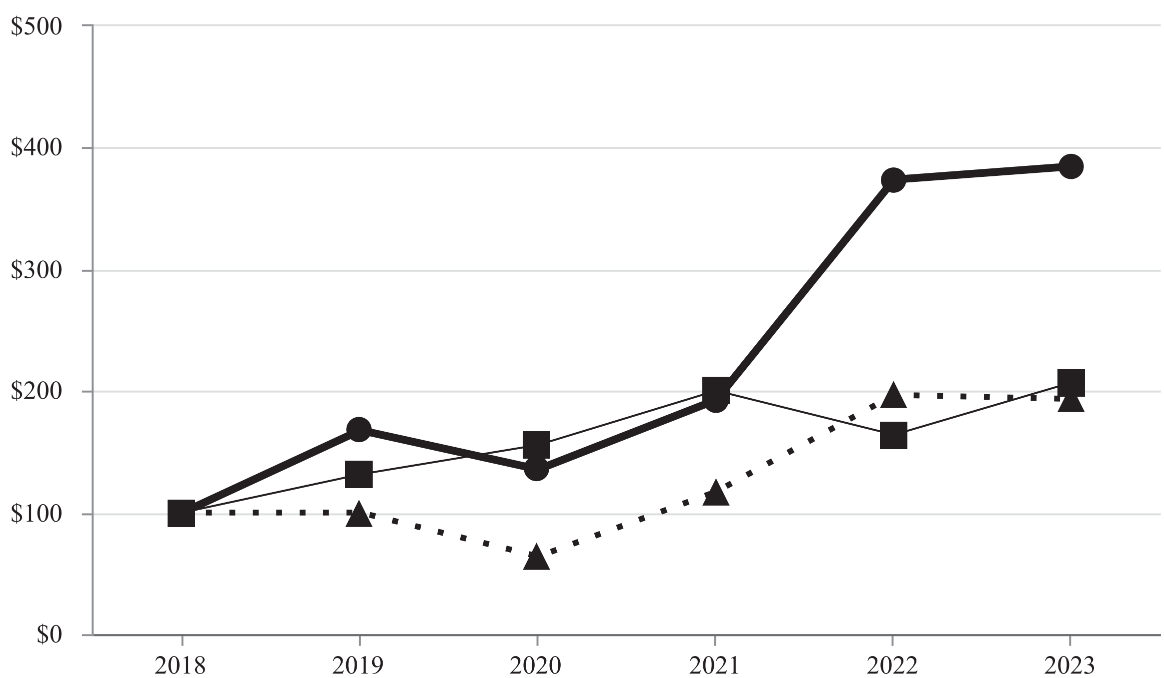
Our common stock is listed on the New York Stock Exchange (ticker symbol: HES). At January 31, 2024, there were 2,494 stockholders (based on the number of holders of record) who owned a total of 307,152,064 shares of common stock. In 2023, cash dividends on common stock totaled $1.75 per share per year ($0.4375 per quarter), $1.50 per share per year ($0.3750 per quarter) in 2022 and $1.00 per share per year ($0.2500 per quarter) in 2021.

Performance Graph

Set forth below is a line graph comparing the five-year shareholder returns on a $100 investment in our common stock assuming reinvestment of dividends, against the cumulative total returns for the following:

- Standard & Poor's (S&P) 500 Stock Index, which includes us.
- 2023 Proxy Peer Group as disclosed in our 2023 Proxy Statement, and including us.

Comparison of Five-Year Shareholder Returns
Years Ended December 31,



	2018	2019	2020	2021	2022	2023
Hess Corporation	$100.00	$167.72	$135.54	$192.62	$373.83	$384.72
S&P 500	$100.00	$131.47	$155.65	$200.29	$163.98	$207.04
Proxy Peer Group	$100.00	$100.02	$63.94	$117.20	$196.77	$193.47

Share Repurchase Activities

On March 1, 2023, our Board of Directors approved a new authorization for the repurchase of our common stock in an aggregate amount of up to $1 billion. This new authorization replaced our previous repurchase authorization which was fully utilized at the end of 2022. There were no shares of our common stock repurchased for the year ended December 31, 2023. The Merger Agreement provides that, during the periods from the date of the Merger Agreement until the closing of the Merger, we are subject to certain restrictions that, among other things, restrict our ability to repurchase, redeem or retire any capital stock of the Corporation.

Equity Compensation Plans

Following is information related to our equity compensation plans at December 31, 2023.

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 (Excluding Securities Reflected in Column*)
Equity compensation plans approved by security holders	1,509,912 (a)	$ 78.85	19,941,906 (b)
Equity compensation plans not approved by security holders	—	—	—

(a) *This amount includes 1,509,912 shares of common stock issuable upon exercise of outstanding stock options. This amount excludes 1,020,653 shares of common stock issued as restricted stock pursuant to our equity compensation plans. This amount also excludes 511,781 PSUs. For the PSUs granted in 2021 and 2022, the number of shares of common stock to be issued will range from 0% to 200% based on our total shareholder return (TSR) relative to the TSR of a predetermined group of peer companies and the S&P 500 index over a three-year performance period ending December 31 of the year prior to settlement of the grant. For the PSU's granted in 2023, the number of shares of common stock to be issued is based on a comparison of the Corporation's total shareholder return compound annual growth rate (TSR CAGR) to the TSR CAGR of the SPDR S&P Oil & Gas Exploration and Production ETF (XOP), with a modifier determined by comparing the Corporation's TSR CAGR to the TSR CAGR of the S&P 500 index, over a three-year performance period ending December 31, 2025. Payout of these PSUs will range from 0% to 200% of the target awards based on the comparison of the Corporation's TSR CAGR to the XOP's TSR CAGR. The modifier can only adjust the payout percentage by plus or minus 10%, up to a maximum of 210% or a minimum of 0%.*

(b) *These securities may be awarded as stock options, restricted stock, PSUs or other awards permitted under our equity compensation plan.*

See *Note 13, Share-based Compensation* in the *Notes to Consolidated Financial Statements* for further discussion of our equity compensation plans.

Item 6. [Reserved]

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

The following discussion should be read together with the *Consolidated Financial Statement*s and the *Notes to Consolidated Financial Statements*, which are included in this Form 10-K in Item 8, and the information set forth in *Part 1, Item 1A. Risk Factors*.

The following Management's Discussion and Analysis of Financial Condition and Results of Operations omits certain discussions of our financial condition and results of operations for the year ended December 31, 2022 compared with the year ended December 31, 2021, which can be found in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* in our 2022 Annual Report on Form 10-K, which was filed with the Securities and Exchange Commission on February 24, 2023, and such comparisons are incorporated herein by reference.

Index

Overview

Hess Corporation is a global E&P company engaged in exploration, development, production, transportation, purchase and sale of crude oil, natural gas liquids, and natural gas with production operations located in the United States (U.S.), Guyana, the Malaysia/Thailand Joint Development Area (JDA) and Malaysia. We conduct exploration activities primarily offshore Guyana, in the U.S. Gulf of Mexico, and offshore Suriname. At the Stabroek Block (Hess 30%), offshore Guyana, we and our partners have discovered a significant resource base and are executing a multi-phased development of the block. We currently have three FPSOs producing, and plan to have six FPSOs with an aggregate expected production capacity of more than 1.2 million gross bopd producing by the end of 2027. The discovered resources to date on the block are expected to underpin the potential for up to ten FPSOs.

Our Midstream operating segment, which includes Hess Corporation's approximate 38% consolidated ownership interest in Hess Midstream LP at December 31, 2023, provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGL; gathering, terminaling, loading and transporting crude oil and NGL; storing and terminaling propane, and water handling services primarily in the Bakken shale play in the Williston Basin area of North Dakota.

On October 22, 2023, we entered into the Merger Agreement with Chevron and the Merger Subsidiary. The Merger Agreement provides that, among other things and subject to the terms and conditions of the Merger Agreement, Merger Subsidiary will be merged with and into Hess, and Hess will be the surviving corporation in the Merger as a direct, wholly-owned subsidiary of Chevron. Under the terms of the Merger Agreement, if the Merger is completed, our stockholders will receive at the effective time of the Merger consideration consisting of 1.025 shares of Chevron common stock for each share of our common stock. The transaction is expected to close mid-2024, subject to shareholder and regulatory approvals and other closing conditions. See *Part I, Item 1A. Risk Factors* for a discussion of risks related to the Merger.

Climate Change, Energy Transition and Our Strategy

We believe climate risks can and should be addressed while at the same time meeting the growing demand for affordable and secure energy, which is essential to ensure a just and orderly energy transition that aligns with the United Nations Sustainable Development Goals. The IEA's 2023 World Energy Outlook provides three scenarios of global energy demand in 2040 based on varying levels of global response to climate change. Under all of the IEA scenarios, oil and natural gas are expected to be needed for decades to come and we expect that significant investment will be required to meet the world's projected growing energy needs, both in renewable energy sources and in oil and gas.

Our strategy is to grow our resource base, have a low cost of supply and sustain cash flow growth. Our strategy aligns with the energy transition needed to reach the energy-related Sustainable Development Goals of the United Nations. Our commitment to sustainability starts with our Board of Directors and senior management and is reinforced throughout our organization. Our Board of Directors, led by its Environmental, Health and Safety Committee, is actively engaged in overseeing Hess' sustainability practices so that sustainability risks and opportunities are taken into account when making strategic decisions. Our Board's Compensation and Management Development Committee has tied executive compensation to advancing our environmental, health and safety goals.

We have five year GHG reduction targets for 2025, which are to reduce operated Scope 1 and 2 GHG emissions intensity by approximately 50% and methane emissions intensity by approximately 50%, both from 2017 levels. In January 2022, we announced our plan to reduce routine flaring at Hess operated assets to zero by the end of 2025. In December 2022, we announced an agreement with the Government of Guyana to purchase 37.5 million REDD+ carbon credits, including current and future issuances, for a minimum of $750 million from 2022 through 2032 to prevent deforestation and support sustainable development in Guyana. This agreement adds to the Corporation's ongoing emissions reduction efforts and is an important part of our commitment to achieve net zero Scope 1 and 2 greenhouse gas emissions on a net equity basis by 2050.

Our business planning includes actions we expect to undertake to continue reducing our carbon footprint consistent with our targets. We also conduct annual scenario planning as a methodology to assess our portfolio's resilience to differing scenarios of energy supply and demand over the longer term, and to inform our understanding of future risks and opportunities in relation to the potential evolution of energy demand, energy mix, the emergence of new technologies, and possible changes by policymakers with respect to greenhouse gas emissions and climate change.

Consolidated Results

Net income attributable to Hess Corporation was $1,382 million in 2023 compared with $2,096 million in 2022. Excluding items affecting comparability of earnings between periods summarized on page 34, adjusted net income was $1,552 million in 2023 compared with $2,176 million in 2022. Net production averaged 394,000 boepd in 2023 and 344,000 boepd in 2022. The average realized crude oil price, including the effect of hedging, was $75.97 per barrel in 2023 and $85.76 per barrel in 2022. Total proved reserves were 1,370 million boe and 1,256 million boe at December 31, 2023 and December 31, 2022, respectively.

Significant 2023 Activities

The following is an update of significant E&P activities during 2023:

E&P assets:

- In North Dakota, net production from the Bakken shale play averaged 182,000 boepd in 2023 (2022: 154,000 boepd). Net production was higher in 2023 reflecting increased drilling and completion activity and higher NGL and natural gas volumes received under percentage of proceeds contracts due to lower commodity prices. NGL and natural gas volumes received under percentage of proceeds contracts were 19,000 boepd in 2023, compared with 10,000 boepd in 2022, due to lower realized NGL and natural gas prices increasing volumes received as consideration for gas processing fees. We added a fourth operated rig in July 2022 and drilled 118 wells and brought 113 wells on production in 2023, bringing the total operated production wells to 1,757 at December 31, 2023. During 2024, we plan to operate four rigs.

- In the Gulf of Mexico, net production averaged 31,000 boepd in 2023 (2022: 31,000 boepd). In July 2023, the Pickerel-1 exploration well (Hess 100%) located in Mississippi Canyon Block 727 completed drilling operations and encountered approximately 90 feet of net pay in high quality, oil bearing, Miocene age reservoir. The well will be a tie-back to the Tubular Bells production facility with first oil expected in mid-2024. In the fourth quarter of 2023, we were the high bidder on 20 leases in the U.S. Department of Interior's Lease Sale 261 for $88 million and we expect to be awarded these leases in the first quarter of 2024. We also spud the Hess operated Black Pearl development well (Hess 25%) in the fourth quarter of 2023. The well is planned as a tie-back to the Stampede production facility. In 2024, we plan to participate in two wells.

- At the Stabroek Block (Hess 30%), offshore Guyana, net production totaled 115,000 bopd in 2023 (2022: 78,000 bopd). The Liza Unity FPSO, which commenced production in February 2022, reached its initial production capacity of approximately 220,000 gross bopd in July 2022, and increased its production capacity to approximately 250,000 bopd in the third quarter of 2023. Further production optimization work is planned in 2024. The third development, Payara, began producing oil in November 2023 from the Prosperity FPSO and reached its initial production capacity of approximately 220,000 gross bopd in January 2024. In 2023, we sold 37 cargos of crude oil from Guyana compared with 26 cargos in 2022.

  Pursuant to the contractual arrangements of the petroleum agreement, a portion of gross production from the block, separate from the joint venture partners' (Co-Venturers) cost oil and profit oil entitlement, is used to satisfy the Co-Venturers' income tax liability. This portion of gross production, referred to as tax barrels, is recognized as Co-Venturer production volumes and estimated proved reserves. Net production from Guyana in 2023 included 14,000 bopd of tax barrels (2022: 7,000 bopd; 2021: 0 bopd).

  A fourth development, Yellowtail, was sanctioned in April 2022 and will utilize the ONE GUYANA FPSO with an expected initial production capacity of approximately 250,000 gross bopd, with first production expected in 2025. Six drill centers are planned with up to 26 production wells and 25 injection wells.

  A fifth development, Uaru, was sanctioned in April 2023 and will utilize the Errea Wittu FPSO with an expected initial production capacity of approximately 250,000 gross bopd, with first production expected in 2026. Ten drill centers are planned with up to 21 production wells and 23 injection wells.

A sixth development, Whiptail, was submitted to the Government of Guyana for approval in the fourth quarter of 2023. Pending government approvals and project sanctioning, the project is expected to have an initial production capacity of approximately 250,000 gross bopd, with first production anticipated in 2027.

A gas to energy project is underway to construct a 130-mile pipeline network and associated infrastructure in order to transport approximately 50 million standard cubic feet of natural gas per day from the Liza Field to a 300 megawatt onshore power plant, which is expected to be constructed and operated by the Government of Guyana. ExxonMobil Guyana Ltd. expects to complete pipeline construction and field hook-up by the end of 2024.

The expiration of the exploration license for the Stabroek Block was extended one year from October 2026 to October 2027, and the end of the first renewal period of the exploration license, which requires the relinquishment of 20% of the acreage not held by discoveries, was extended one year from October 2023 to October 2024, both as a result of force majeure due to the COVID-19 pandemic.

In 2023, the operator drilled a total of three successful exploration and appraisal wells that encountered oil and two unsuccessful exploration wells for which the well costs were expensed. Subsequent to December 31, 2023, the operator completed one successful exploration well and one successful appraisal well. In 2024, the operator plans to utilize six drillships to continue to perform exploration, appraisal, and development activities.

At the Kaieteur Block, offshore Guyana, we relinquished our 20% participating interest, subject to government approval, and recognized exploration expense of $9 million in 2023.

- In the Gulf of Thailand, net production from Block A-18 of the JDA averaged 36,000 boepd in 2023 (2022: 38,000 boepd), including contribution from unitized acreage in Malaysia, while net production from North Malay Basin averaged 30,000 boepd in 2023 (2022: 26,000 boepd). During 2023, we drilled seven production wells at the JDA and nine production wells at North Malay Basin, and we plan to continue development drilling in 2024.
- In Canada, offshore Newfoundland (Hess 25%), the operator completed drilling of the Ephesus exploration well in June 2023. The well did not encounter commercial quantities of hydrocarbons and well costs incurred of $34 million were recorded to exploration expense in 2023.

The following is an update of significant Midstream activities during 2023:

- Hess Midstream completed two underwritten public equity offerings of an aggregate of approximately 24.3 million Class A shares held by affiliates of Hess and GIP. As a result of these transactions, Hess received net proceeds of $167 million.
- HESM Opco, a consolidated subsidiary of Hess Midstream LP, repurchased an aggregate of approximately 13.6 million HESM Opco Class B units held by affiliates of Hess and GIP in multiple transactions for total proceeds of $400 million, financed by HESM Opco's revolving credit facility, of which Hess received proceeds of $188 million.

Liquidity and Capital and Exploratory Expenditures

At December 31, 2023, cash and cash equivalents were $1,688 million (2022: $2,486 million) and consolidated debt was $8,613 million (2022: $8,281 million), which includes Hess Midstream debt that is nonrecourse to Hess Corporation of $3,211 million at December 31, 2023 (2022: $2,886 million).

Capital and exploratory expenditures were as follows (in millions):

	2023	2022	2021
E&P Capital and Exploratory Expenditures:			
United States			
North Dakota	**$ 1,138**	$ 807	$ 522
Offshore and other	**290**	224	103
Total United States	**1,428**	1,031	625
Guyana	**2,518**	1,345	1,016
Malaysia and JDA	**189**	275	154
Other (a)	**41**	70	34
E&P Capital and Exploratory Expenditures	**$ 4,176**	$ 2,721	$ 1,829
Exploration Expenses Charged to Income Included Above:			
United States	**$ 106**	$ 107	$ 90
International	**37**	25	41
Total Exploration Expenses Charged to Income included above	**$ 143**	$ 132	$ 131
Midstream Capital Expenditures:			
Midstream Capital Expenditures	**$ 246**	$ 232	$ 183

(a) Other includes our interests in Libya (sold in November 2022) and Denmark (sold in August 2021), and certain non-producing countries.

Our E&P capital and exploratory expenditures are projected to be approximately $4.2 billion in 2024, compared with $4.2 billion in 2023. Capital investment for our Midstream operations is expected to be in the range of $250 million to $275 million in 2024, compared with $246 million in 2023.

Consolidated Results of Operations

Results by Segment:

The after-tax income (loss) by major operating activity is summarized below:

	2023	2022	2021
	(In millions, except per share amounts)		
Net Income Attributable to Hess Corporation:			
Exploration and Production	**$ 1,601**	$ 2,396	$ 770
Midstream	**252**	269	286
Corporate, Interest and Other	**(471)**	(569)	(497)
Total	**$ 1,382**	$ 2,096	$ 559
Net Income Attributable to Hess Corporation Per Common Share:			
Basic	**$ 4.52**	$ 6.80	$ 1.82
Diluted	**$ 4.49**	$ 6.77	$ 1.81

In the following discussion and elsewhere in this report, the financial effects of certain transactions are disclosed on an after-tax basis. Management reviews segment earnings on an after-tax basis and uses after-tax amounts in its review of variances in segment earnings. Management believes that after-tax amounts are a preferable method of explaining variances in earnings, since they show the entire effect of a transaction rather than only the pre-tax amount. After-tax amounts are determined by applying the income tax rate in each tax jurisdiction to pre-tax amounts.

Items Affecting Comparability of Earnings Between Periods:

The following table summarizes, on an after-tax basis, items of income (expense) that are included in net income and affect comparability of earnings between periods. The items in the table below are explained on pages 39 through 41.

	2023	2022	2021
		(In millions)	
Items Affecting Comparability of Earnings Between Periods, After Income Taxes:			
Exploration and Production	$ **(101)**	$ 22	$ (118)
Midstream	—	—	—
Corporate, Interest and Other	**(69)**	(102)	—
Total	$ **(170)**	$ (80)	$ (118)

The following table presents the pre-tax amount of items affecting comparability of income (expense) by financial statement line item in the *Statement of Consolidated Income* on page 57. The items in the table below are explained on pages 39 through 41.

	Before Income Taxes		
	2023	2022	2021
		(In millions)	
Gains on asset sales, net	$ —	$ 98	$ 29
Other, net	**(17)**	—	—
Exploration expenses, including dry holes and lease impairment	**(52)**	—	—
General and administrative expenses	**(52)**	(124)	—
Impairment and other	**(82)**	(54)	(147)
Total Items Affecting Comparability of Earnings Between Periods, Pre-Tax	$ **(203)**	$ (80)	$ (118)

Reconciliations of GAAP and Non-GAAP Measures:

The following table reconciles reported net income attributable to Hess Corporation and adjusted net income attributable to Hess Corporation:

	2023	2022	2021
		(In millions)	
Adjusted Net Income Attributable to Hess Corporation:			
Net income attributable to Hess Corporation	$ **1,382**	$ 2,096	$ 559
Less: Total items affecting comparability of earnings between periods, after-tax	**(170)**	(80)	(118)
Adjusted Net Income Attributable to Hess Corporation	$ **1,552**	$ 2,176	$ 677

The following table reconciles reported net cash provided by (used in) operating activities and net cash provided by (used in) operating activities before changes in operating assets and liabilities:

	2023	2022	2021
		(In millions)	
Net cash provided by (used in) operating activities before changes in operating assets and liabilities:			
Net cash provided by (used in) operating activities	$ **3,942**	$ 3,944	$ 2,890
Changes in operating assets and liabilities	**552**	1,177	101
Net cash provided by (used in) operating activities before changes in operating assets and liabilities	$ **4,494**	$ 5,121	$ 2,991

Adjusted net income attributable to Hess Corporation is a non-GAAP financial measure, which we define as reported net income attributable to Hess Corporation excluding items identified as affecting comparability of earnings between periods, which are summarized on pages 39 through 41. Management uses adjusted net income to evaluate the Corporation's operating performance and believes that investors' understanding of our performance is enhanced by disclosing this measure, which excludes certain items that management believes are not directly related to ongoing operations and are not indicative of future business trends and operations.

Net cash provided by (used in) operating activities before changes in operating assets and liabilities presented in this report is a non-GAAP measure, which we define as reported net cash provided by (used in) operating activities excluding changes in operating assets and liabilities. Management uses net cash provided by (used in) operating activities before changes in operating assets and liabilities to evaluate the Corporation's ability to internally fund capital expenditures, pay dividends and service debt and believes that investors' understanding of our ability to generate cash to fund these items is enhanced by disclosing this measure, which excludes working capital and other movements that may distort assessment of our performance between periods.

These measures are not, and should not be viewed as, substitutes for GAAP net income and net cash provided by (used in) operating activities.

Comparison of Results

Exploration and Production

Following is a summarized statement of income for our E&P operations:

	2023	2022	2021
		(In millions)	
Revenues and Non-Operating Income			
Sales and other operating revenues	**$ 10,500**	$ 11,324	$ 7,473
Gains on asset sales, net	**—**	76	29
Other, net	**50**	102	64
Total revenues and non-operating income	**10,550**	11,502	7,566
Costs and Expenses			
Marketing, including purchased oil and gas	**2,809**	3,394	2,119
Operating costs and expenses	**1,479**	1,186	965
Production and severance taxes	**216**	255	172
Midstream tariffs	**1,245**	1,193	1,094
Exploration expenses, including dry holes and lease impairment	**317**	208	162
General and administrative expenses	**254**	224	191
Depreciation, depletion and amortization	**1,852**	1,520	1,361
Impairment and other	**82**	54	147
Total costs and expenses	**8,254**	8,034	6,211
Results of Operations Before Income Taxes	**2,296**	3,468	1,355
Provision for income taxes	**695**	1,072	585
Net Income Attributable to Hess Corporation	**$ 1,601**	$ 2,396	$ 770

Excluding the E&P items affecting comparability of earnings between periods in the table on page 39, the changes in E&P results are primarily attributable to changes in selling prices, production and sales volumes, marketing expenses, cash operating costs, Midstream tariffs, DD&A expense, exploration expenses and income taxes, as discussed below.

Selling Prices: Average worldwide realized crude oil selling prices, including hedging, were 11% lower in 2023 compared with the prior year, primarily due to the decrease in Brent and WTI crude oil prices. In addition, realized worldwide selling prices for NGL decreased in 2023 by 41% and worldwide natural gas prices decreased in 2023 by 23%, compared with the prior year. In total, lower realized selling prices reduced after-tax results by approximately $1,560 million, compared with 2022. Our average selling prices were as follows:

	2023	2022	2021
Average Selling Prices (a)			
Crude Oil – Per Barrel (Including Hedging)			
United States			
North Dakota	**$ 70.44**	$ 81.06	$ 55.57
Offshore	**72.06**	81.38	60.09
Total United States	**70.80**	81.14	56.64
Guyana	**80.72**	89.86	68.57
Malaysia and JDA	**75.51**	89.77	71.00
Other (b)	—	93.67	66.39
Worldwide	**75.97**	85.76	60.08
Crude Oil – Per Barrel (Excluding Hedging)			
United States			
North Dakota	**$ 73.80**	$ 91.26	$ 59.90
Offshore	**75.39**	91.51	64.77
Total United States	**74.15**	91.32	61.05
Guyana	**82.20**	96.52	71.07
Malaysia and JDA	**75.51**	89.77	71.00
Other (b)	—	101.92	69.25
Worldwide	**78.29**	94.15	63.90
Natural Gas Liquids – Per Barrel			
United States			
North Dakota	**$ 20.77**	$ 35.09	$ 30.74
Offshore	**20.87**	35.24	26.40
Worldwide	**20.77**	35.09	30.40
Natural Gas – Per Mcf			
United States			
North Dakota	**$ 1.68**	$ 5.50	$ 4.08
Offshore	**2.16**	6.21	3.25
Total United States	**1.76**	5.66	3.82
Malaysia and JDA	**5.95**	5.62	5.15
Other (b)	—	5.93	3.40
Worldwide	**4.32**	5.64	4.60

(a) Selling prices in the United States and Guyana are adjusted for certain processing and distribution fees included in Marketing expenses. Excluding these fees worldwide selling prices for 2023 would be $79.30 per barrel for crude oil (including hedging) (2022: $89.50; 2021: $64.25), $81.62 per barrel for crude oil (excluding hedging) (2022: $97.89; 2021: $68.07), $21.01 per barrel for NGL (2022: $35.44; 2021: $30.61) and $4.47 per mcf for natural gas (2022: $5.76; 2021: $4.71).

(b) Other includes our interests in Libya (sold in November 2022) and Denmark (sold in August 2021).

Crude oil hedging activities in 2023 were a net loss of $190 million before and after income taxes, and a net loss of $585 million before and after income taxes in 2022.

Production Volumes: Our daily worldwide net production was as follows:

	2023	2022	2021
		(In thousands)	
Crude Oil – Barrels			
United States			
North Dakota	**83**	75	80
Offshore	**22**	22	29
Total United States	**105**	97	109
Guyana	**115**	78	30
Malaysia and JDA	**5**	4	3
Other (a)	**—**	15	21
Total	**225**	194	163
Natural Gas Liquids – Barrels			
United States			
North Dakota	**67**	53	49
Offshore	**2**	2	4
Total United States	**69**	55	53
Natural Gas – Mcf			
United States			
North Dakota	**191**	156	162
Offshore	**43**	44	72
Total United States	**234**	200	234
Malaysia and JDA	**368**	360	347
Other (a)	**—**	10	10
Total	**602**	570	591
Barrels of Oil Equivalent	**394**	344	315
Crude oil and natural gas liquids as a share of total production	**75 %**	72 %	69 %

(a) Other includes our interests in Libya (sold in November 2022) and Denmark (sold in August 2021). Net production from Libya was 17,000 boepd boepd for 2022 (2021: 20,000 boepd). Net production from Denmark was 3,000 boepd for 2021.

Net production variances related to 2023 and 2022 are summarized as follows:

United States: North Dakota net production was higher in 2023, reflecting increased drilling and completion activity and higher NGL and natural gas volumes received under percentage of proceeds contracts due to lower commodity prices.

International: Net production in Guyana was higher in 2023, primarily due to the Liza Unity FPSO, which commenced production in February 2022 and reached its initial production capacity of approximately 220,000 gross bopd in July 2022. The Liza Unity FPSO increased its production capacity to approximately 250,000 gross bopd in the third quarter of 2023. The third development, Payara, began producing oil in November 2023 from the Prosperity FPSO and reached its initial production capacity of approximately 220,000 gross bopd in January 2024. Net production from Guyana included 14,000 bopd of tax barrels in 2023 (2022: 7,000 bopd).

Sales Volumes: Higher sales volumes in 2023 increased after-tax earnings by approximately $1,650 million. Net worldwide sales volumes from Hess net production, which excludes sales volumes of crude oil, NGLs and natural gas purchased from third parties, were as follows:

	2023	2022	2021
		(In thousands)	
Crude oil – barrels (a)	**81,941**	69,679	63,540
Natural gas liquids – barrels	**25,184**	19,843	19,406
Natural gas – mcf	**219,750**	208,001	215,589
Barrels of Oil Equivalent	**143,750**	124,189	118,878
Crude oil – barrels per day	**225**	191	174
Natural gas liquids – barrels per day	**69**	54	53
Natural gas – mcf per day	**602**	570	591
Barrels of Oil Equivalent Per Day	**394**	340	326

(a) Sales volumes in 2021 include 4.2 million barrels of crude oil that were stored on VLCCs at December 31, 2020 and sold in the first quarter of 2021.

Marketing, including purchased oil and gas (Marketing expense): Marketing expense is mainly comprised of costs to purchase crude oil, NGL and natural gas from our partners in Hess operated wells or other third parties, primarily in the U.S., and transportation and other distribution costs for U.S. and Guyana marketing activities. Marketing expense was lower in 2023, compared to 2022, primarily due to lower prices paid for purchased volumes.

Cash Operating Costs: Cash operating costs consist of operating costs and expenses, production and severance taxes and E&P general and administrative expenses. Cash operating costs increased in 2023, compared to 2022, primarily due to the production ramp up in Guyana following the startup of Liza Phase 2 in February 2022 and Payara in November 2023, increased maintenance activity in North Dakota, and higher workover costs in the Gulf of Mexico.

Midstream Tariffs Expense: Tariffs expense increased in 2023, compared to 2022, primarily due to higher throughput volumes and tariff rates, partially offset by lower fees incurred under minimum volume commitments.

DD&A Expense: DD&A expense was higher in 2023, compared to 2022, primarily due to higher production from Guyana following the startup of Liza Phase 2 in February 2022 and first production from Payara in November 2023, and Malaysia and JDA due to new wells and facilities online in 2023.

Unit Costs: Unit cost per boe information is based on total E&P net production volumes and excludes items affecting comparability of earnings as disclosed on page 39. Actual unit costs are as follows:

	Actual		
	2023	2022	2021
Cash operating costs (a)	**$ 13.57**	$ 13.28	$ 11.55
DD&A expense (b)	**12.89**	12.13	11.84
Total Production Unit Costs	**$ 26.46**	$ 25.41	$ 23.39

(a) Cash operating costs per boe, excluding Libya, were $13.77 in 2022 (2021: $12.11).
(b) DD&A expense per boe, excluding Libya, was $12.59 in 2022 (2021: $12.43).

Exploration Expenses: Exploration expenses, including items affecting comparability of earnings described below, were as follows:

	2023	2022	2021
		(In millions)	
Exploratory dry hole costs (a)	**$ 147**	$ 56	$ 11
Exploration lease impairment	**27**	20	20
Geological and geophysical expense and exploration overhead	**143**	132	131
	$ 317	$ 208	$ 162

(a) In 2023, dry hole costs primarily related to the Ephesus exploration well, offshore Newfoundland, Canada, the Kokwari-1 and Fish/Tarpon-1 exploration wells at the Stabroek Block, offshore Guyana, and the write-off of a previously capitalized exploratory well (see Items Affecting Comparability of Earnings Between Periods on page 39). Dry hole costs primarily related to the Fish/Tarpon-1 well and Banjo-1 well in 2022 and the Koebi-1 well in 2021 at the Stabroek Block, offshore Guyana.

Income Taxes: In 2023, E&P income tax expense was $695 million compared to $1,072 million in 2022. Income tax expense from Libya operations, sold in November 2022, was $527 million in 2022. The absence of Libya tax expense in 2023 compared to 2022 was partially offset by higher income tax expense in Guyana as a result of higher pre-tax income.

We are generally not recognizing deferred tax benefit or expense in certain countries while we maintain valuation allowances against net deferred tax assets in these jurisdictions in accordance with U.S. GAAP. As of December 31, 2023, we have a valuation allowance in our *Consolidated Balance Sheet* of $3,652 million. In December 2023, the valuation allowance established against the portion of the net deferred tax assets in Malaysia related to the Marginal Field tax ring-fence was released in the amount of $33 million as a result of the emergence from a cumulative loss position and positive evidence from forecasted pre-tax income from operations. See *E&P Items Affecting Comparability of Earnings Between Periods* below. The remaining valuation allowance in Malaysia is associated with net deferred tax assets of other tax ring-fences which lack sufficient positive evidence to support realizability. While we emerged from a recent cumulative loss position in the U.S. (non-Midstream) in 2023, the cumulative income position is near breakeven. Until we see a more significant and sustained pattern of objectively verifiable income, we do not assign significant weight to subjective long-term projections of future income and thus maintain a full valuation allowance against our U.S. (non-Midstream) federal and state deferred tax assets. If anticipated future earnings are exceeded, sufficient positive evidence may become available to support the release of valuation allowance in the future. This would result in the recognition of certain deferred tax assets on the balance sheet and a decrease to income tax expense for the period in which the release is recorded.

Actual effective tax rates are as follows:

	2023	**2022**	**2021**
	%	**%**	**%**
Effective income tax benefit (expense) rate	**(30)**	(31)	(43)
Adjusted effective income tax benefit (expense) rate (a)	**(30)**	(19)	(15)

(a) Excludes any contribution from Libya, sold in November 2022, and items affecting comparability of earnings.

Items Affecting Comparability of Earnings Between Periods: Reported E&P earnings include the following items affecting comparability of income (expense):

	Before Income Taxes			**After Income Taxes**		
	2023	**2022**	**2021**	**2023**	**2022**	**2021**
	(In millions)					
Impairment and other	**$ (82)**	$ (54)	$ (147)	**$ (82)**	$ (54)	$ (147)
Dry hole expenses	**(52)**	—	—	**(52)**	—	—
Gains on asset sales, net	**—**	76	29	**—**	76	29
Release of deferred tax asset valuation allowance	**—**	—	—	**33**	—	—
	$ (134)	$ 22	$ (118)	**$ (101)**	$ 22	$ (118)

The pre-tax amounts of E&P items affecting comparability of income (expense) as presented in the *Statement of Consolidated Income* are as follows:

	Before Income Taxes		
	2023	**2022**	**2021**
	(In millions)		
Gains on asset sales, net	**$ —**	$ 76	$ 29
Exploration expenses, including dry holes and lease impairment	**(52)**	—	—
Impairment and other	**(82)**	(54)	(147)
	$ (134)	$ 22	$ (118)

2023:

- *Dry hole expenses:* We recorded a pre-tax charge of $52 million ($52 million after income taxes) to write-off the Huron-1 exploration well in the Gulf of Mexico which completed in 2022, based on the decision by the Corporation and its partners in the fourth quarter of 2023 to exit the project. See *Note 3, Property, Plant and Equipment* in the *Notes to Consolidated Financial Statements*.

- *Impairment and other:* We recorded a pre-tax charge of $82 million ($82 million after income taxes) that resulted from revisions to our estimated abandonment obligations in the West Delta Field in the Gulf of Mexico. These abandonment obligations were assigned to us as a former owner after they were discharged from Fieldwood Energy LLC as part of its approved bankruptcy plan in 2021. See *Note 12, Impairment and Other* in the *Notes to Consolidated Financial Statements*.

- *Release of deferred tax asset valuation allowance:* We recorded a noncash income tax benefit of $33 million, which resulted from the reversal of a valuation allowance against net deferred tax assets in Malaysia.

2022:

- *Gains on asset sales, net:* We recognized a pre-tax gain of $76 million ($76 million after income taxes) associated with the sale of our interest in the Waha Concession in Libya.

- *Impairment and other:* We recorded charges of $28 million ($28 million after income taxes) that resulted from updates to our estimated abandonment liabilities for non-producing properties in the Gulf of Mexico and $26 million ($26 million after income taxes) related to the Penn State Field in the Gulf of Mexico. See *Note 12, Impairment and Other* in the *Notes to Consolidated Financial Statements*.

2021:

- *Gains on asset sales, net:* We recognized a pre-tax gain of $29 million ($29 million after income taxes) associated with the sale of our interests in Denmark.

- *Impairment and other:* We recorded a charge of $147 million ($147 million after income taxes) in connection with estimated abandonment obligations in the West Delta Field in the Gulf of Mexico. These abandonment obligations were assigned to us as a former owner after they were discharged from Fieldwood Energy LLC as part of its approved bankruptcy plan. See *Note 12, Impairment and Other* in the *Notes to Consolidated Financial Statements*.

Midstream

Following is a summarized statement of income for our Midstream operations:

	2023	2022	2021
		(In millions)	
Revenues and Non-Operating Income			
Sales and other operating revenues	**$ 1,349**	$ 1,273	$ 1,204
Other, net	**8**	8	10
Total revenues and non-operating income	**1,357**	1,281	1,214
Costs and Expenses			
Operating costs and expenses	**313**	280	289
General and administrative expenses	**26**	23	22
Interest expense	**179**	150	105
Depreciation, depletion and amortization	**193**	181	166
Total costs and expenses	**711**	634	582
Results of Operations Before Income Taxes	**646**	647	632
Provision for income taxes	**38**	27	15
Net income	**608**	620	617
Less: Net income attributable to noncontrolling interests	**356**	351	331
Net Income Attributable to Hess Corporation	**$ 252**	$ 269	$ 286

Sales and other operating revenues increased from 2022 primarily due to higher throughput volumes and tariff rates, partially offset by lower fees earned from minimum volume commitments. Operating costs and expenses increased from 2022 primarily due to higher maintenance costs. Interest expense increased from 2022 primarily due to higher interest rates on the credit facilities and higher borrowings on the revolving credit facility. DD&A expense increased from 2022 primarily due to additional assets placed in service. Provision for income taxes increased from 2022 primarily driven by increased ownership of HESM Opco by Hess Midstream LP following the equity offerings and unit repurchase transactions in 2022 and 2023.

Corporate, Interest and Other

The following table summarizes Corporate, Interest and Other expenses:

	2023	2022	2021
		(In millions)	
Corporate and other expenses (excluding items affecting comparability)	**$ 103**	$ 124	$ 121
Interest expense	**347**	353	376
Less: Capitalized interest	**(48)**	(10)	—
Interest expense, net	**299**	343	376
Corporate, Interest and Other expenses before income taxes	**402**	467	497
Provision (benefit) for income taxes	**—**	—	—
Corporate, Interest and Other expenses after income taxes	**402**	467	497
Items affecting comparability of earnings between periods, after income taxes	**69**	102	—
Total Corporate, Interest and Other expenses after income taxes	**$ 471**	$ 569	$ 497

Corporate and other expenses, excluding items affecting comparability, were lower in 2023 compared to 2022 primarily due to higher interest income partially offset by higher legal and professional fees and other administrative expenses. Interest expense, net was lower in 2023 compared to 2022 due to capitalized interest that commenced upon sanctioning of the Yellowtail development in Guyana in April 2022 and the Uaru development in Guyana in April 2023.

Items Affecting Comparability of Earnings Between Periods: Corporate, Interest and Other results included the following items affecting comparability of income (expense):

2023:

- *Litigation costs:* We incurred pre-tax charges totaling $52 million ($52 million after income taxes) for litigation related costs associated with our former downstream business, HONX, Inc., which are included in *General and administrative expenses* in the *Statement of Consolidated Income*. See *Note 17, Guarantees, Contingencies and Commitments* in the *Notes to Consolidated Financial Statements*.
- *Pension settlement:* We recorded a noncash charge to recognize unamortized actuarial losses of $17 million ($17 million after income taxes) resulting from the payment of lump sums to certain participants in the Hess Corporation Employees' Pension Plan. The charge is included in *Other, net* in the *Statement of Consolidated Income*. See *Note 9, Retirement Plans* in the *Notes to Consolidated Financial Statements*.

2022:

- *Gains on asset sales, net:* We recorded a pre-tax gain of $22 million ($22 million after income taxes) associated with the sale of real property related to our former downstream business.
- *Litigation costs:* We incurred pre-tax charges totaling $124 million ($124 million after income taxes) for litigation related costs associated with our former downstream business, HONX, Inc., which are included in *General and administrative expenses* in the *Statement of Consolidated Income*. See *Note 17, Guarantees, Contingencies and Commitments* in the *Notes to Consolidated Financial Statements*.

Liquidity and Capital Resources

The following table sets forth certain relevant measures of our liquidity and capital resources at December 31:

	2023	2022
	(In millions, except ratio)	
Cash and cash equivalents (a)	**$ 1,688**	$ 2,486
Current portion of long-term debt	**311**	3
Total debt (b)	**8,613**	8,281
Total equity	**9,602**	8,496
Debt to capitalization ratio for debt covenants (c)	**33.6 %**	36.1 %

(a) Includes $6 million of cash attributable to our Midstream segment at December 31, 2023 (2022: $4 million) of which, $5 million is held by Hess Midstream LP at December 31, 2023 (2022: $3 million).

(b) Includes $3,211 million of debt outstanding from our Midstream segment at December 31, 2023 (2022: $2,886 million) that is non-recourse to Hess Corporation.

(c) Total Consolidated Debt of Hess Corporation (including finance leases and excluding Midstream non-recourse debt) as a percentage of Total Capitalization of Hess Corporation as defined under Hess Corporation's revolving credit facility financial covenants. Total Capitalization excludes the impact of noncash impairment charges and non-controlling interests. See Note 7, Debt in the Notes to Consolidated Financial Statements.

Cash Flows

The following table sets forth a summary of our cash flows:

	2023	2022	2021
		(In millions)	
Net cash provided by (used in):			
Operating activities	**$ 3,942**	$ 3,944	$ 2,890
Investing activities	**(4,113)**	(2,555)	(1,325)
Financing activities	**(627)**	(1,616)	(591)
Net Increase (Decrease) in Cash and Cash Equivalents	**$ (798)**	$ (227)	$ 974

***Operating Activities*:** Net cash provided by operating activities was $3,942 million in 2023 (2022: $3,944 million), while net cash provided by operating activities before changes in operating assets and liabilities was $4,494 million in 2023 (2022: $5,121 million). Net cash provided by operating activities before changes in operating assets and liabilities decreased from 2022 primarily due to lower realized selling prices partially offset by higher sales volumes. Changes in operating assets and liabilities in 2023 reduced net cash provided by operating activities by $552 million primarily due to premiums paid for crude oil hedge contracts and payments for abandonment activities. Changes in operating assets and liabilities in 2022 reduced net cash provided by operating activities by $1,177 million reflecting payments of approximately $470 million for accrued Libyan income tax and royalties at December 31, 2021, premiums paid for crude oil hedge contracts, payments for abandonment activities, and the purchase of REDD+ carbon credits.

Investing Activities: Additions to Property, Plant and Equipment were $4,108 million in 2023 (2022: $2,725 million). The increase is primarily due to development activities in Guyana and higher drilling activity in the Bakken. Proceeds from asset sales were $3 million in 2023 (2022: $178 million).

Financing Activities: Common stock dividends paid were $539 million in 2023 (2022: $465 million) reflecting a 17% increase in our declared dividend on common stock. In 2022, we paid $630 million for settled common stock repurchases and we repaid the remaining $500 million outstanding under our $1.0 billion term loan.

Net borrowings (repayments) of debt with maturities of 90 days or less in 2023 related to the HESM Opco revolving credit facility, while borrowings in 2022 resulted from the issuance by HESM Opco of $400 million of 5.500% fixed-rate senior unsecured notes due 2030. The proceeds from these borrowings were used to finance the repurchases of HESM Opco Class B units. In 2023, we received net proceeds of $167 million from the public offering of Class A shares in Hess Midstream LP (2022: $146 million). Net cash outflows to noncontrolling interests were $550 million in 2023 (2022: $510 million) which included $212 million paid to GIP for the repurchase by HESM Opco of GIP-owned Class B units (2022: $200 million).

Future Capital Requirements and Resources

At December 31, 2023, we had $1.68 billion in cash and cash equivalents, excluding Midstream, and total liquidity, including available committed credit facilities, of approximately $5.0 billion. In 2024, based on current forward strip crude oil prices, we expect cash flow from operating activities and cash and cash equivalents at December 31, 2023 will be sufficient to fund any upcoming debt maturities, and our capital investment and capital return programs. Depending on market conditions, we may take any of the following steps, or a combination thereof, to improve our liquidity and financial position: reduce the planned capital program and other cash outlays, including dividends, pursue asset sales, borrow against our committed revolving credit facility, or issue debt or equity securities. These actions are subject to certain limitations under the Merger Agreement. See *Part I, Item 1A. Risk Factors* for a discussion of risks related to the Merger.

The table below summarizes the capacity, usage, and available capacity of our borrowing and letter of credit facilities at December 31, 2023:

	Expiration Date	Capacity	Borrowings	Letters of Credit Issued	Total Used	Available Capacity
				(In millions)		
Hess Corporation						
Revolving credit facility	July 2027	$ 3,250	$ —	$ —	$ —	$ 3,250
Committed lines	Various (a)	100	—	2	2	98
Uncommitted lines	Various (a)	86	—	86	86	—
Total – Hess Corporation		$ 3,436	$ —	$ 88	$ 88	$ 3,348
Midstream						
Revolving credit facility (b)	July 2027	$ 1,000	$ 340	$ —	$ 340	$ 660
Total – Midstream		$ 1,000	$ 340	$ —	$ 340	$ 660

(a) Committed and uncommitted lines have expiration dates through 2024.
(b) This credit facility may only be utilized by HESM Opco and is non-recourse to Hess Corporation.

Hess Corporation:

The revolving credit facility can be used for borrowings and letters of credit. Borrowings on the facility will generally bear interest at 1.400% above SOFR, though the interest rate is subject to adjustment based on the credit rating of the Corporation's senior, unsecured, non-credit enhanced long-term debt. The revolving credit facility is subject to customary representations, warranties, customary events of default and covenants, including a financial covenant limiting the ratio of Total Consolidated Debt to Total Capitalization of the Corporation and its consolidated subsidiaries to 65%, and a financial covenant limiting the ratio of secured debt to Consolidated Net Tangible Assets of the Corporation and its consolidated subsidiaries to 15% (as these capitalized terms are defined in the credit agreement for the revolving credit facility). The indentures for the Corporation's fixed-rate senior unsecured notes limit the ratio of secured debt to Consolidated Net Tangible Assets (as that term is defined in the indentures) to 15%. As of December 31, 2023, Hess Corporation was in compliance with these financial covenants. The most restrictive of the financial covenants relating to our fixed-rate senior unsecured notes and our revolving credit facility would allow us to borrow up to an additional $2,515 million of secured debt at December 31, 2023.

We have a shelf registration under which we may issue additional debt securities, warrants, common stock or preferred stock.

Midstream:

At December 31, 2023, HESM Opco had $1.4 billion of senior secured syndicated credit facilities, consisting of a $1.0 billion revolving credit facility and a $400 million term loan facility. Borrowings under the term loan facility will generally bear interest at SOFR plus an applicable margin ranging from 1.650% to 2.550%, while the applicable margin for the syndicated revolving credit facility ranges from 1.375% to 2.050%. Pricing levels for the facility fee and interest-rate margins are based on HESM Opco's ratio of total debt to EBITDA (as defined in the credit facilities). If HESM Opco obtains an investment grade credit rating, the pricing levels will be based on HESM Opco's credit ratings in effect from time to time. The credit facilities contain covenants that require HESM Opco to maintain a ratio of total debt to EBITDA (as defined in the credit facilities) for the prior four fiscal quarters of not greater than 5.00 to 1.00 as of the last day of each fiscal quarter (5.50 to 1.00 during the specified period following certain acquisitions) and, prior to HESM Opco obtaining an investment grade credit rating, a ratio of secured debt to EBITDA for the prior four fiscal quarters of not greater than 4.00 to 1.00 as of the last day of each fiscal quarter. HESM Opco was in compliance with these financial covenants at December 31, 2023. The credit facilities are secured by first-priority perfected liens on substantially all of the assets of HESM Opco and its direct and indirect wholly owned material domestic subsidiaries, including equity interests directly owned by such entities, subject to certain customary exclusions. At December 31, 2023, borrowings of $340 million were drawn under HESM Opco's revolving credit facility, and borrowings of $397 million, excluding deferred issuance costs, were drawn under HESM Opco's term loan facility. Borrowings under these credit facilities are non-recourse to Hess Corporation.

Credit Ratings

All three major credit rating agencies that rate the senior unsecured debt of Hess Corporation have assigned an investment grade credit rating. At December 31, 2023, our credit ratings were BBB- at S&P Global Ratings, Baa3 at Moody's Investors Service, and BBB at Fitch Ratings. Subsequent to the announcement of the Merger all three agencies placed our credit ratings on review for positive action in connection with the Merger.

At December 31, 2023, HESM Opco's senior unsecured debt is rated BB+ by S&P Global Ratings and Fitch Ratings, and Ba2 by Moody's Investors Service.

Cash Requirements:

Our cash obligations and commitments over the next twelve months include accounts payable, accrued liabilities, the current portion of long-term debt, interest, lease payments, and purchase obligations which cover a portion of our planned capital expenditure program in 2024 and include commitments for oil and gas production expenses, carbon credits, transportation and related contracts, seismic purchases and other normal business expenses.

Our long-term cash obligations and commitments include:

- ***Debt and interest:*** See *Note 7*, *Debt* in the *Notes to Consolidated Financial Statements*.
- ***Operating and finance leases:*** The Corporation and certain of its subsidiaries lease drilling rigs, equipment, logistical assets (offshore vessels, aircraft, and shorebases), and office space for varying periods. See *Note 6*, *Leases* in the *Notes to Consolidated Financial Statements*.
- ***Purchase obligations:*** We were contractually committed at December 31, 2023 for certain long-term capital expenditures and operating expenses. Long-term obligations for operating expenses include commitments for oil and gas production expenses, transportation and related contracts, carbon credits, seismic purchases and other normal business expenses. See *Note 17*, G*uarantees, Contingencies and Commitments* in the *Notes to Consolidated Financial Statements*.
- ***Asset retirement obligations:*** See *Note 8*, *Asset Retirement Obligations* in the *Notes to Consolidated Financial Statements*.
- ***Post-retirement plan liabilities:*** We have certain unfunded post-retirement plans, including our post-retirement medical plan. See *Note 9*, *Retirement Plans* in the *Notes to Consolidated Financial Statements*.
- ***Uncertain income tax positions:*** See *Note 14*, *Income Taxes* in the *Notes to Consolidated Financial Statements*.

Off-Balance Sheet Arrangements

See *Note 17, Guarantees, Contingencies and Commitments* in the *Notes to Consolidated Financial Statements*.

Foreign Operations

We conduct E&P activities outside the U.S., principally in Guyana, the Joint Development Area of Malaysia/Thailand, Malaysia, and Suriname. Therefore, we are subject to the risks associated with foreign operations. See *Part 1, Item 1A. Risk Factors* for further details.

Critical Accounting Policies and Estimates

Accounting policies and estimates affect the recognition of assets and liabilities in the *Consolidated Balance Sheet* and revenues and expenses in the *Statement of Consolidated Income*. The accounting methods used can affect net income, equity and various financial statement ratios. However, our accounting policies generally do not change cash flows or liquidity.

Accounting for Exploration and Development Costs: E&P activities are accounted for using the successful efforts method. Costs of acquiring unproved and proved oil and gas leasehold acreage, including lease bonuses, brokers' fees and other related costs are capitalized. Annual lease rentals, exploration expenses and exploratory dry hole costs are expensed as incurred. Costs of drilling and equipping productive wells, including development dry holes, and related production facilities are capitalized.

The costs of exploratory wells that find oil and gas reserves are capitalized pending determination of whether proved reserves have been found. Exploratory drilling costs remain capitalized after drilling is completed if (1) the well has found a sufficient quantity of reserves to justify completion as a producing well and (2) sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. If either of those criteria is not met, or if there is substantial doubt about the economic or operational viability of the project, the capitalized well costs are charged to expense. Indicators of sufficient progress in assessing reserves, and the economic and operating viability of a project include: commitment of project personnel, active negotiations for sales contracts with customers, negotiations with governments, operators and contractors and firm plans for additional drilling and other factors.

Crude Oil and Natural Gas Reserves: The determination of estimated proved reserves is a significant element in arriving at the results of operations of E&P activities. The estimates of proved reserves affect well capitalizations, the unit of production depreciation rates of proved properties and wells and equipment, as well as impairment testing of oil and gas assets.

For reserves to be booked as proved they must be determined with reasonable certainty to be economically producible from known reservoirs under existing economic conditions, operating methods and government regulations. In addition, government and project operator approvals must be obtained and, depending on the amount of the project cost, senior management or the Board of

Directors must commit to fund the project. We maintain our own internal reserve estimates that are calculated by technical staff that work directly with the oil and gas properties. Our technical staff update reserve estimates throughout the year based on evaluations of new wells, performance reviews, new technical data and other studies. To provide consistency throughout the Corporation, standard reserve estimation guidelines, definitions, reporting reviews and approval practices are used. The internal reserve estimates are subject to internal technical audits and senior management review. We also engage an independent third-party consulting firm to audit approximately 80% of our total proved reserves each year.

Proved reserves are calculated using the average price during the twelve-month period ending December 31 determined as an unweighted arithmetic average of the price on the first day of each month within the year, unless prices are defined by contractual agreements, excluding escalations based on future conditions. As discussed in *Part 1, Item 1A. Risk Factors*, crude oil prices are volatile which can have an impact on our proved reserves. Crude oil prices used in the determination of proved reserves at December 31, 2023 were $78.10 per barrel for WTI (2022: $94.13) and $82.51 per barrel for Brent (2022: $97.98). At December 31, 2023, spot prices closed at $71.65 per barrel for WTI and $77.59 per barrel for Brent. If crude oil prices in 2024 are at levels below that used in determining 2023 proved reserves, we may recognize negative revisions to our December 31, 2024 proved undeveloped reserves. In addition, we may recognize negative revisions to proved developed reserves, which can vary significantly by asset due to differing operating cost structures. Conversely, price increases in 2024 above those used in determining 2023 proved reserves could result in positive revisions to proved developed and proved undeveloped reserves at December 31, 2024. It is difficult to estimate the magnitude of any potential net negative or positive change in proved reserves at December 31, 2024, due to numerous currently unknown factors, including 2024 crude oil prices, the amount of any additions to proved reserves, positive or negative revisions in proved reserves related to 2024 reservoir performance, the levels to which industry costs will change in response to 2024 crude oil prices, and management's plans as of December 31, 2024 for developing proved undeveloped reserves. A 10% change in proved developed and proved undeveloped reserves at December 31, 2023 would result in an approximate $225 million pre-tax change in depreciation, depletion, and amortization expense for 2024 based on projected production volumes. See the *Supplementary Oil and Gas Data* on pages 92 through 101 in the accompanying financial statements for additional information on our oil and gas reserves.

Impairment of Long-lived Assets: We review long-lived assets, including oil and gas fields, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. Long-lived assets are tested based on identifiable cash flows that are largely independent of the cash flows of other assets and liabilities. If the carrying amounts of the long-lived assets are not expected to be recovered by estimated undiscounted future net cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is measured based on the estimated fair value of the assets generally determined by discounting anticipated future net cash flows, an income valuation approach, or by a market-based valuation approach, which are Level 3 fair value measurements.

In the case of oil and gas fields, the present value of future net cash flows is based on management's best estimate of future prices, which is determined with reference to recent historical prices and published forward prices, applied to projected production volumes and discounted at a risk-adjusted rate. The projected production volumes represent reserves, including probable reserves, expected to be produced based on a stipulated amount of capital expenditures. The production volumes, prices and timing of production are consistent with internal projections and other externally reported information. Oil and gas prices used for determining asset impairment will generally differ from those used in the standardized measure of discounted future net cash flows, since the standardized measure requires the use of historical twelve-month average prices.

Our impairment tests of long-lived E&P producing assets are based on our best estimates of future production volumes (including recovery factors), selling prices, operating and capital costs, the timing of future production and other factors, which are updated each time an impairment test is performed. We could experience an impairment in the future if one or a combination of the following occur: the projected production volumes from oil and gas fields decrease, crude oil and natural gas selling prices decline significantly for an extended period or future estimated capital and operating costs increase significantly.

Hess Midstream LP: We consolidate the activities of our interest in Hess Midstream LP, which qualifies as a variable interest entity (VIE) under U.S. generally accepted accounting principles. We have concluded that we are the primary beneficiary of the VIE, as defined in the accounting standards, since we have the power through Hess Corporation's approximate 38% consolidated ownership interest in Hess Midstream LP to direct those activities that most significantly impact the economic performance of Hess Midstream LP, and are obligated to absorb losses or have the right to receive benefits that could potentially be significant to Hess Midstream LP. This conclusion was based on a qualitative analysis that considered Hess Midstream LP's governance structure, the commercial agreements between Hess Midstream LP and us, and the voting rights established between the members.

Income Taxes: Judgments are required in the determination and recognition of income tax assets and liabilities in the financial statements. These judgments include the requirement to recognize the financial statement effect of a tax position only when management believes it is more likely than not, based on the technical merits, that the position will be sustained upon examination.

We have net operating loss carryforwards or credit carryforwards in multiple jurisdictions and have recognized deferred tax assets for those losses and credits. Additionally, we have deferred tax assets due to temporary differences between the book basis and tax basis of certain assets and liabilities. Regular assessments are made as to the likelihood of those deferred tax assets being realized. If, when tested under the relevant accounting standards, it is more likely than not that some or all of the deferred tax assets will not be realized, a valuation allowance is established to reduce the deferred tax assets to the amount that is expected to be realized.

The accounting standards require the evaluation of all available positive and negative evidence giving weight based on the evidence's relative objectivity. In evaluating potential sources of positive evidence, we consider the reversal of taxable temporary differences, taxable income in carryback and carryforward periods, the availability of tax planning strategies, the existence of appreciated assets, estimates of future taxable income, and other factors. Estimates of future taxable income are based on assumptions of oil and gas reserves, selling prices, and other subjective operating assumptions that are consistent with internal business forecasts. In evaluating potential sources of negative evidence, we consider a cumulative loss in recent years, any history of operating losses or tax credit carryforwards expiring unused, losses expected in early future years, unsettled circumstances that, if unfavorably resolved, would adversely affect future operations and profit levels on a continuing basis in future years, and any carryback or carryforward period so brief that a significant deductible temporary difference expected to reverse in a single year would limit realization of tax benefits. A recent cumulative loss constitutes objective negative evidence to which the accounting standards require we assign significant weight relative to subjective evidence such as our estimates of future taxable income. We are generally not recognizing deferred tax benefit or expense in certain countries, primarily the United States (non-Midstream) while we maintain valuation allowances against net deferred tax assets in these jurisdictions.

At December 31, 2023, the *Consolidated Balance Sheet* reflects a $3,652 million valuation allowance against the net deferred tax assets for multiple jurisdictions based on the evaluation of the accounting standards described above. The amount of the deferred tax asset considered realizable, however, could be adjusted if objective negative evidence in the form of cumulative losses is no longer present and additional weight can be given to subjective evidence. In December 2023, the valuation allowance established against the portion of the net deferred tax assets in Malaysia related to the Marginal Field tax ring-fence was released in the amount of $33 million as a result of the emergence from a cumulative loss position and positive evidence from forecasted pre-tax income from operations. The remaining valuation allowance in Malaysia is associated with net deferred tax assets of other tax ring-fences which lack sufficient positive evidence to support realizability. While we emerged from a recent cumulative loss position in the U.S. (non-Midstream) in 2023, the cumulative income position is near breakeven. Until we see a more significant and sustained pattern of objectively verifiable income, we do not assign significant weight to subjective long-term projections of future income and thus maintain a full valuation allowance against our U.S. (non-Midstream) federal and state deferred tax assets. If anticipated future earnings are exceeded, sufficient positive evidence may become available to support the release of valuation allowance in the future. This would result in the recognition of certain deferred tax assets on the balance sheet and a decrease to income tax expense for the period in which the release is recorded.

Asset Retirement Obligations: We have legal obligations to remove and dismantle long-lived assets and to restore land or seabed at certain E&P locations. In accordance with generally accepted accounting principles, we recognize a liability for the fair value of required asset retirement obligations. In addition, the fair value of any legally required conditional asset retirement obligation is recorded if the liability can be reasonably estimated. We capitalize such costs as a component of the carrying amount of the underlying assets in the period in which the liability is incurred. In subsequent periods, the liability is accreted, and the asset is depreciated over the useful life of the related asset. We estimate the fair value of these obligations by discounting projected future payments that will be required to satisfy the obligations. In determining these estimates, we are required to make several assumptions and judgments related to the scope of dismantlement, timing of settlement, interpretation of legal requirements, inflationary factors and discount rate. In addition, there are other external factors, which could significantly affect the ultimate settlement costs or timing for these obligations including changes in environmental regulations and other statutory requirements, fluctuations in industry costs and foreign currency exchange rates and advances in technology. As a result, our estimates of asset retirement obligations are subject to revision due to the factors described above. Changes in estimates prior to settlement result in adjustments to both the liability and related asset values, unless the field has ceased production, in which case changes are recognized in our *Statement of Consolidated Income*. See *Note 8, Asset Retirement Obligations* in the *Notes to Consolidated Financial Statements*.

Retirement Plans: We have funded non-contributory defined benefit pension plans, an unfunded supplemental pension plan and an unfunded postretirement medical plan. We recognize the net change in the funded status of the projected benefit obligation for these plans in the *Consolidated Balance Sheet*. The determination of the obligations and expenses related to these plans are based on several actuarial assumptions. These assumptions represent estimates made by us, some of which can be affected by external factors. The most significant assumptions relate to:

Discount rates used for measuring the present value of future plan obligations and net periodic benefit cost: The discount rates used to estimate our projected benefit obligations and net periodic benefit cost is based on a portfolio of high-quality, fixed income debt instruments with maturities that approximate the expected payment of plan obligations. At December 31, 2023, a 0.25% decrease in the discount rate assumptions would increase projected benefit obligations by approximately $65 million and would increase forecasted 2024 annual net periodic benefit expense by approximately $1 million. The increase in the projected benefit obligations would decrease the funded status of our pension plans, but any decrease in the funded status would be partially mitigated by increases in the fair value of fixed income investments in the asset portfolios.

Expected long-term rates of returns on plan assets: The expected rate of return on plan assets is developed from the expected future returns for each asset category, weighted by the target allocation of plan assets to that asset category. The future expected rate of return assumptions for individual asset categories are largely based on inputs from various investment experts regarding their future return expectations for particular asset categories. At December 31, 2023, a 0.25% decrease in the expected long-term rates of return on plan assets assumption would increase forecasted 2024 annual net periodic benefit expense by approximately $5 million.

Other assumptions include the rate of future increases in compensation levels and expected participant mortality.

Derivatives: We utilize derivative instruments, including futures, forwards, options and swaps, individually or in combination to mitigate our exposure to fluctuations in the prices of crude oil and natural gas, as well as changes in interest and foreign currency exchange rates. All derivative instruments are recorded at fair value in our *Consolidated Balance Sheet*. Our policy for recognizing the changes in fair value of derivatives varies based on the designation of the derivative. The changes in fair value of derivatives that are not designated as hedges are recognized currently in earnings. Derivatives may be designated as hedges of expected future cash flows or forecasted transactions (cash flow hedges), or hedges of changes in fair value of recognized assets and liabilities or of unrecognized firm commitments (fair value hedges). Changes in fair value of derivatives that are designated as cash flow hedges are recorded as a component of *Other Comprehensive Income (Loss)*. Amounts included in *Accumulated Other Comprehensive Income (Loss)* for cash flow hedges are reclassified into earnings in the same period that the hedged item is recognized in earnings. Changes in fair value of derivatives designated as fair value hedges are recognized currently in earnings. The change in fair value of the related hedged item is recorded as an adjustment to its carrying amount and recognized currently in earnings.

Fair Value Measurements: We use various valuation approaches in determining fair value for financial instruments, including the market and income approaches. Our fair value measurements also include non-performance risk and time value of money considerations. Counterparty credit is considered for financial assets, and our credit is considered for financial liabilities.

We also record certain nonfinancial assets and liabilities at fair value when required by generally accepted accounting principles. These fair value measurements are recorded in connection with business combinations, qualifying non-monetary exchanges, the initial recognition of asset retirement obligations and any impairment of long-lived assets, equity method investments or goodwill.

We determine fair value in accordance with the fair value measurements accounting standard which established a hierarchy for the inputs used to measure fair value based on the source of the inputs, which generally range from quoted prices for identical instruments in a principal trading market (Level 1) to estimates determined using related market data (Level 3), including discounted cash flows and other unobservable data. Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. When Level 1 inputs are available within a particular market, those inputs are selected for determination of fair value over Level 2 or 3 inputs in the same market. Multiple inputs may be used to measure fair value; however, the level assigned to a fair value measurement is based on the lowest significant input level within this fair value hierarchy.

Environment, Health and Safety

Our long-term vision and values provide a foundation for how we do business and define our commitment to meeting high standards of corporate citizenship and creating a long lasting positive impact on the communities where we do business. Our strategy is reflected in our EHS & SR policies and by a management system framework that helps protect our workforce, customers and local communities. Our management systems are intended to promote internal consistency, adherence to policy objectives and continual improvement in EHS & SR performance. Improved performance may, in the short-term, increase our operating costs and could also require increased capital expenditures to reduce potential risks to our assets, reputation and license to operate. In addition to enhanced EHS & SR performance, improved productivity and operational efficiencies may be realized from investments in EHS & SR. We have programs in place to evaluate regulatory compliance, audit facilities, train employees, prevent and manage risks and emergencies and to generally meet corporate EHS & SR goals and objectives.

Environmental Matters

We recognize that climate change is a global environmental concern. We assess, monitor and take measures to reduce our carbon footprint at existing and planned operations. The EPA has adopted a series of GHG monitoring, reporting, and emissions control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting further legislation to reduce GHG emissions. For example, in December 2023, the EPA issued a final rule to establish comprehensive standards of performance and emission guidelines for methane and volatile organic compound emissions from existing operations in the oil and gas sector, including the exploration and production, transmission, processing, and storage segments. In addition, the IRA includes a methane emissions reduction program for petroleum and natural gas systems, which requires the EPA to impose a “waste emissions charge” on excess methane emissions from certain natural gas and oil sources that are required to report under EPA’s Greenhouse Gas Reporting Program beginning January 1, 2024 and also provides significant funding and incentives for research and development of competing low carbon energy production methods. In January of 2024, the EPA released its proposed rule to implement the methane emissions fee with a proposed effective date in 2025 for reporting 2024 emissions. Furthermore, states have taken measures to reduce emissions of GHGs, primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs. At the international level, the Paris Agreement on climate change aimed to enhance global response to global temperature changes and to reduce GHG emissions, among other things. We are committed to complying with all GHG emissions regulations that apply to our operations, including those related to venting or flaring of natural gas, and the responsible management of GHG emissions at our facilities. While we monitor climate-related regulatory initiatives and international public policy issues, the current state of ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties, legislation or new regulations. However, future restrictions on emissions of GHGs, or related measures to encourage use of low carbon energy could result in higher capital expenditures and operating expenses for us and the oil and gas industry in general and may reduce demand for our products, as described under *Regulatory, Legal and Environmental Risks* in *Part 1*, *Item 1A. Risk Factors*.

We will have continuing expenditures for environmental assessment and remediation. Sites where corrective action may be necessary include E&P facilities, sites from discontinued operations where we retained liability and, although not currently significant, EPA "Superfund" sites where we have been named a potentially responsible party. We accrue for environmental assessment and remediation expenses when the future costs are probable and reasonably estimable. For additional information, see *Item 3. Legal Proceedings*. At December 31, 2023, our reserve for estimated remediation liabilities was approximately $50 million. We expect that existing reserves for environmental liabilities will adequately cover costs to assess and remediate known sites. Our remediation spending was approximately $28 million in 2023 (2022: $23 million; 2021: $16 million). The amount of other expenditures incurred to comply with federal, state, local and foreign country environmental regulations is difficult to quantify as such costs are captured as mostly indistinguishable components of our capital expenditures and operating expenses.

As an element of our EHS and SR strategy, we purchase carbon credits annually to offset 100 percent of our estimated Scope 3 business travel emissions and 100 percent of our estimated Scope 1 and Scope 3 emissions associated with operating the Corporation's truck fleet, aviation activities (aircraft and helicopters) and personal and rental vehicle miles driven on company business. We also offset purchased electricity used in our operations from nonrenewable sources by purchasing renewable energy certificates. The cost of these purchased and retired renewable energy certificates was not material to our financial results in 2023 and are included in *Operating costs and expenses* in the *Statement of Consolidated Income*.

In December 2022, we announced an agreement with the Government of Guyana to purchase 37.5 million REDD+ carbon credits, including current and future issuances, for a minimum of $750 million from 2022 through 2032 to prevent deforestation and support sustainable development in Guyana. These credits will be on the ART Registry and will be independently verified to represent permanent and additional emissions reductions under ART's REDD+ Environmental Standard 2.0 (TREES). This agreement adds to the Corporation's ongoing emissions reduction efforts and is an important part of our commitment to achieve net zero Scope 1 and 2 greenhouse gas emissions on a net equity basis by 2050. As of December 31, 2023, we have purchased 10 million REDD+ carbon credits registered on the ART Registry for $150 million under this agreement, which is included in non-current *Other assets* in the *Consolidated Balance Sheet*.

Health and Safety Matters

The crude oil and natural gas industry is regulated at federal, state, local and foreign government levels regarding the health and safety of E&P operations. Such laws and regulations relate to, among other matters, occupational safety, the use of hydraulic fracturing to stimulate crude oil and natural gas production, well control and integrity, process safety and equipment integrity, and may include permitting and disclosure requirements, operating restrictions and other conditions on the development of crude oil and natural gas. The level of our expenditures to comply with federal, state, local and foreign country health and safety regulations is difficult to quantify as such costs are captured as mostly indistinguishable components of our capital expenditures and operating expenses. While compliance with laws and regulations relating to health and safety matters increases the overall cost of business for us and the oil and gas industry in general, it has not had, to date, a material adverse effect on our operations, financial condition or results of operations.

Occupational Safety: We are subject to the requirements set forth under federal workplace standards by the OSHA and comparable state statutes that regulate the protection of the health and safety of workers. Under OSHA and other federal and state occupational safety and health laws and laws of foreign countries in which we operate, we must develop, maintain and disclose certain information about hazardous materials used, released, or produced in our operations.

Production and Well Integrity: Our U.S. onshore production facilities are subject to U.S. federal government, state and local regulations regarding the use of hydraulic fracturing and well control and integrity. Our offshore production facilities in the Gulf of Mexico are subject to the U.S. federal government's Safety and Environmental Management System regulations, which provide a systematic approach for identifying, managing and mitigating hazards. Adapting to new technical standards and procedures in production and in our well integrity management system is fundamental to our aim of protecting the environment as well as the health and safety of our workforce and the communities in which we operate, and to safeguarding our product.

Process Safety and Equipment Integrity: We are also regulated at federal, state, local and foreign government levels regarding process safety and the integrity of our equipment, including OSHA's Process Safety Management of Highly Hazardous Chemicals standard. ICE are barriers and safeguards that prevent or mitigate process safety incidents through detection, isolation, containment, control or emergency preparedness and response within our facilities. We have established ICE performance standards, which set specific requirements and criteria for inspections and tests that help to ensure ICE barriers are effective. We conduct assessments collaboratively with our operated assets, subject matter experts and technical authorities to evaluate compliance with corporate and asset environment, health and safety standards and procedures, as well as with applicable regulations. For additional information on our emergency response and incident mitigation activities, see *Emergency Preparedness and Response Plans and Procedures* in *Items 1 and 2. Business and Properties*.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

In the normal course of our business, we are exposed to commodity risks related to changes in the prices of crude oil, NGL, and natural gas as well as changes in interest rates and foreign currency values. In the disclosures that follow, financial risk management activities refer to the mitigation of these risks through hedging activities.

Controls: We maintain a control environment under the direction of our Chief Risk Officer. Controls over instruments used in financial risk management activities include volumetric and term limits. Our Treasury department is responsible for administering and monitoring foreign exchange rate and interest rate hedging programs using similar controls and processes, where applicable. Hedging strategies are reviewed annually by the Audit Committee of the Board of Directors.

Instruments: We primarily use forward commodity contracts, foreign exchange forward contracts, futures, swaps, and options in our risk management activities. These contracts are generally widely traded instruments with standardized terms. The following describes these instruments and how we use them:

- *Swaps:* We use financially settled swap contracts with third parties as part of our financial risk management activities. Cash flows from swap contracts are determined based on underlying commodity prices, interest rates or foreign exchange rates and are typically settled over the life of the contract.
- *Forward Foreign Exchange Contracts:* We enter into forward contracts, primarily for the British Pound and Malaysian Ringgit, which commit us to buy or sell a fixed amount of those currencies at a predetermined exchange rate on a future date.
- *Exchange-traded Contracts:* We may use exchange-traded contracts, including futures, on a number of different underlying energy commodities. These contracts are settled daily with the relevant exchange and may be subject to exchange position limits.
- *Options:* Options on various underlying energy commodities include exchange-traded and third-party contracts and have various exercise periods. As a purchaser of options, we pay a premium at the outset and are exposed to the favorable consequence of collecting payment upon exercise depending upon the underlying commodity price movement. As a seller of options, we receive a premium at the outset and are exposed to the unfavorable consequence of having to make payment upon exercise depending upon the underlying commodity price movement.

Financial Risk Management Activities

We have outstanding foreign exchange contracts with notional amounts totaling $226 million at December 31, 2023 that are used to reduce our exposure to fluctuating foreign exchange rates for various currencies. The change in fair value of foreign exchange contracts from a 10% strengthening or weakening in the U.S. Dollar exchange rate is estimated to be a gain of approximately $20 million or a loss of approximately $25 million at December 31, 2023.

At December 31, 2023, our total long-term debt, which was substantially comprised of fixed-rate instruments, had a carrying value of $8,613 million and a fair value of $9,006 million. A 15% increase or decrease in interest rates would decrease or increase the fair value of debt by approximately $400 million or $440 million, respectively. Any changes in interest rates do not impact our cash outflows associated with fixed-rate interest payments or settlement of debt principal, unless a debt instrument is repurchased prior to maturity.

See *Note 19, Financial Risk Management Activities* in the *Notes to Consolidated Financial Statements* for further details.

Item 8. Financial Statements and Supplementary Data

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
INDEX TO FINANCIAL STATEMENTS

Schedules have been omitted because of the absence of the conditions under which they are required or because the required information is presented in the financial statements or the notes thereto.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2023.

The Corporation's independent registered public accounting firm, Ernst & Young LLP, has audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2023, as stated in their report, which is included herein.

By John P. Rielly
John P. Rielly
Executive Vice President and
Chief Financial Officer

By John B. Hess
John B. Hess
Chief Executive Officer

February 26, 2024

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Hess Corporation

Opinion on Internal Control Over Financial Reporting

We have audited Hess Corporation and consolidated subsidiaries' internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Hess Corporation and consolidated subsidiaries (the Corporation) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Corporation as of December 31, 2023 and 2022, the related statements of consolidated income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2023, and the related notes and our report dated February 26, 2024 expressed an unqualified opinion thereon.

Basis for Opinion

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

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

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

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

Ernst & Young LLP

New York, New York
February 26, 2024

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Hess Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Hess Corporation and consolidated subsidiaries (the Corporation) as of December 31, 2023 and 2022, the related statements of consolidated income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2023, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Corporation at December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Corporation's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 26, 2024 expressed an unqualified opinion thereon.

Basis for Opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

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

	Depreciation, depletion and amortization of proved oil and natural gas properties
Description of the Matter	The net book value of the Corporation's exploration and production assets was $14,196 million at December 31, 2023, and depreciation, depletion and amortization (DD&A) expense was $1,852 million for the year then ended. As described in Note 1 to the consolidated financial statements, the Corporation follows the successful efforts method of accounting for its oil and gas exploration and production 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. Proved oil and gas reserves are prepared using standard geological and engineering methods generally recognized in the petroleum industry based on evaluations of estimated in-place hydrocarbon volumes using financial and non-financial inputs. Significant judgment is required by the Corporation's internal engineering staff in interpreting the data used to estimate reserves. Estimating proved reserves also requires the selection and evaluation of inputs, including historical production, oil and natural gas price assumptions as well as future operating and capital costs assumptions, among others. Management used independent petroleum engineering specialists to audit approximately 89% of the Corporation's proved reserves at December 31, 2023 as prepared by the Corporation's internal engineering staff.

Auditing the Corporation's DD&A expense calculation is especially complex because of the use of the work of the Corporation's internal engineering staff and the independent petroleum engineering specialists and the evaluation of management's determination of the inputs described above used by these engineering specialists in estimating proved oil and gas reserves.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of internal controls that address the risks of material misstatement relating to the DD&A expense calculation. This included controls over the completeness and accuracy of the financial data used in estimating proved oil and gas reserves.

Our testing of the Corporation’s DD&A expense calculation included, among other procedures, evaluating the professional qualifications and objectivity of the Corporation’s internal petroleum engineering specialist responsible for overseeing the preparation of the Corporation’s reserve estimates and of the independent petroleum engineering specialist used to audit the estimates. On a sample basis, we tested the completeness and accuracy of the financial data used in the estimation of proved oil and gas reserves by agreeing significant inputs to source documentation, where available, and assessing the inputs for reasonableness based on review of corroborative evidence and consideration of any contrary evidence. Additionally, we performed analytic and lookback procedures on select inputs into the oil and gas reserve estimate as well as on the outputs. Finally, we tested that the DD&A expense calculations are based on the appropriate proved oil and gas reserve balances from the Corporation’s reserve report.

Ernst & Young LLP

We have served as the Corporation’s auditor since 1971
New York, New York
February 26, 2024

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	December 31, 2023	December 31, 2022
	(In millions, except share amounts)	
Assets		
Current Assets:		
Cash and cash equivalents	**$ 1,688**	$ 2,486
Accounts receivable:		
From contracts with customers	**1,180**	1,041
Joint venture and other	**150**	121
Inventories	**304**	217
Other current assets	**108**	66
Total current assets	**3,430**	3,931
Property, plant and equipment:		
Total — at cost	**36,771**	32,592
Less: Reserves for depreciation, depletion, amortization and lease impairment	**19,339**	17,494
Property, plant and equipment — net	**17,432**	15,098
Operating lease right-of-use assets — net	**720**	570
Finance lease right-of-use assets — net	**108**	126
Goodwill	**360**	360
Deferred income taxes	**320**	133
Post-retirement benefit assets	**685**	648
Other assets	**952**	829
Total Assets	**$ 24,007**	$ 21,695
Liabilities		
Current Liabilities:		
Accounts payable	**$ 402**	$ 285
Accrued liabilities	**2,102**	1,840
Taxes payable	**85**	47
Current portion of long-term debt	**311**	3
Current portion of operating and finance lease obligations	**370**	221
Total current liabilities	**3,270**	2,396
Long-term debt	**8,302**	8,278
Long-term operating lease obligations	**459**	469
Long-term finance lease obligations	**156**	179
Deferred income taxes	**608**	418
Asset retirement obligations	**1,186**	1,034
Other liabilities and deferred credits	**424**	425
Total Liabilities	**14,405**	13,199
Equity		
Hess Corporation stockholders' equity:		
Common stock, par value $1.00; Authorized — 600,000,000 shares:		
Issued — 307,158,272 shares (2022: 306,176,864)	**307**	306
Capital in excess of par value	**6,495**	6,206
Retained earnings	**2,318**	1,474
Accumulated other comprehensive income (loss)	**(134)**	(131)
Total Hess Corporation stockholders' equity	**8,986**	7,855
Noncontrolling interests	**616**	641
Total equity	**9,602**	8,496
Total Liabilities and Equity	**$ 24,007**	$ 21,695

The consolidated financial statements reflect the successful efforts method of accounting for oil and gas exploration and production activities.

See accompanying Notes to Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED INCOME

	Year Ended December 31, 2023	2022	2021
	(In millions, except per share amounts)		
Revenues and Non-Operating Income			
Sales and other operating revenues	**$ 10,511**	$ 11,324	$ 7,473
Gains on asset sales, net	**2**	101	29
Other, net	**132**	145	81
Total revenues and non-operating income	**10,645**	11,570	7,583
Costs and Expenses			
Marketing, including purchased oil and gas	**2,732**	3,328	2,034
Operating costs and expenses	**1,776**	1,452	1,229
Production and severance taxes	**216**	255	172
Exploration expenses, including dry holes and lease impairment	**317**	208	162
General and administrative expenses	**527**	531	340
Interest expense	**478**	493	481
Depreciation, depletion and amortization	**2,046**	1,703	1,528
Impairment and other	**82**	54	147
Total costs and expenses	**8,174**	8,024	6,093
Income Before Income Taxes	**2,471**	3,546	1,490
Provision for income taxes	**733**	1,099	600
Net Income	**1,738**	2,447	890
Less: Net income attributable to noncontrolling interests	**356**	351	331
Net Income Attributable to Hess Corporation	**$ 1,382**	$ 2,096	$ 559
Net Income Attributable to Hess Corporation Per Common Share:			
Basic	**$ 4.52**	$ 6.80	$ 1.82
Diluted	**$ 4.49**	$ 6.77	$ 1.81
Weighted Average Number of Common Shares Outstanding:			
Basic	**305.9**	308.1	307.4
Diluted	**307.6**	309.6	309.3
Common Stock Dividends Per Share	**$ 1.75**	$ 1.50	$ 1.00

See accompanying Notes to Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2023	**2022**	**2021**
		(In millions)	
Net Income	**$ 1,738**	$ 2,447	$ 890
Other Comprehensive Income (Loss):			
Derivatives designated as cash flow hedges			
Effect of hedge (gains) losses reclassified to income	**190**	585	243
Income taxes on effect of hedge (gains) losses reclassified to income	**—**	—	—
Net effect of hedge (gains) losses reclassified to income	**190**	585	243
Change in fair value of cash flow hedges	**(190)**	(517)	(315)
Income taxes on change in fair value of cash flow hedges	**—**	—	—
Net change in fair value of cash flow hedges	**(190)**	(517)	(315)
Change in derivatives designated as cash flow hedges, after taxes	**—**	68	(72)
Pension and other postretirement plans			
(Increase) reduction in unrecognized actuarial losses	**(22)**	201	355
Income taxes on actuarial changes in plan liabilities	**2**	(5)	—
(Increase) reduction in unrecognized actuarial losses, net	**(20)**	196	355
Amortization of net actuarial losses	**18**	12	66
Income taxes on amortization of net actuarial losses	**(1)**	(1)	—
Net effect of amortization of net actuarial losses	**17**	11	66
Change in pension and other postretirement plans, after taxes	**(3)**	207	421
Other Comprehensive Income (Loss)	**(3)**	275	349
Comprehensive Income	**1,735**	2,722	1,239
Less: Comprehensive income attributable to noncontrolling interests	**356**	351	331
Comprehensive Income Attributable to Hess Corporation	**$ 1,379**	$ 2,371	$ 908

See accompanying Notes to Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2023	**2022**	**2021**
		(In millions)	
Cash Flows From Operating Activities			
Net income	**$ 1,738**	$ 2,447	$ 890
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
(Gains) on asset sales, net	**(2)**	(101)	(29)
Depreciation, depletion and amortization	**2,046**	1,703	1,528
Impairment and other	**82**	54	147
Exploratory dry hole costs	**147**	56	11
Exploration lease impairment	**27**	20	20
Pension settlement loss	**17**	2	9
Stock compensation expense	**87**	83	77
Noncash (gains) losses on commodity derivatives, net	**156**	548	216
Provision (benefit) for deferred income taxes and other tax accruals	**196**	309	122
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	**(324)**	(301)	(748)
(Increase) decrease in inventories	**(87)**	2	135
Increase (decrease) in accounts payable and accrued liabilities	**253**	50	241
Increase (decrease) in taxes payable	**38**	(465)	447
Changes in other operating assets and liabilities	**(432)**	(463)	(176)
Net cash provided by (used in) operating activities	**3,942**	3,944	2,890
Cash Flows From Investing Activities			
Additions to property, plant and equipment – E&P	**(3,884)**	(2,487)	(1,584)
Additions to property, plant and equipment – Midstream	**(224)**	(238)	(163)
Proceeds from asset sales, net of cash sold	**3**	178	427
Other, net	**(8)**	(8)	(5)
Net cash provided by (used in) investing activities	**(4,113)**	(2,555)	(1,325)
Cash Flows From Financing Activities			
Net borrowings (repayments) of debt with maturities of 90 days or less	**322**	(86)	(80)
Debt with maturities of greater than 90 days:			
Borrowings	**—**	420	750
Repayments	**(3)**	(510)	(510)
Cash dividends paid	**(539)**	(465)	(311)
Common stock acquired and retired	**(20)**	(630)	—
Proceeds from sale of Class A shares of Hess Midstream LP	**167**	146	178
Noncontrolling interests, net	**(550)**	(510)	(664)
Employee stock options exercised	**10**	52	77
Payments on finance lease obligations	**(10)**	(9)	(10)
Other, net	**(4)**	(24)	(21)
Net cash provided by (used in) financing activities	**(627)**	(1,616)	(591)
Net Increase (Decrease) in Cash and Cash Equivalents	**(798)**	(227)	974
Cash and Cash Equivalents at Beginning of Year	**2,486**	2,713	1,739
Cash and Cash Equivalents at End of Year	**$ 1,688**	$ 2,486	$ 2,713

See accompanying Notes to Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED EQUITY

	Common Stock	Capital in Excess of Par	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Hess Stockholders' Equity	Noncontrolling Interests	Total Equity
Balance at December 31, 2020	$ 307	$ 5,684	$ 130	$ (755)	$ 5,366	$ 969	$ 6,335
Net income	—	—	559	—	559	331	890
Other comprehensive income (loss)	—	—	—	349	349	—	349
Share-based compensation	3	153	—	—	156	—	156
Dividends on common stock	—	—	(310)	—	(310)	—	(310)
Sale of Class A shares of Hess Midstream LP	—	152	—	—	152	103	255
Repurchase of Class B units of Hess Midstream Operations LP	—	28	—	—	28	(390)	(362)
Noncontrolling interests, net	—	—	—	—	—	(287)	(287)
Balance at December 31, 2021	$ 310	$ 6,017	$ 379	$ (406)	$ 6,300	$ 726	$ 7,026
Net income	—	—	2,096	—	2,096	351	2,447
Other comprehensive income (loss)	—	—	—	275	275	—	275
Share-based compensation	1	136	—	—	137	—	137
Dividends on common stock	—	—	(465)	—	(465)	—	(465)
Sale of Class A shares of Hess Midstream LP	—	130	—	—	130	88	218
Repurchase of Class B units of Hess Midstream Operations LP	—	32	—	—	32	(215)	(183)
Common stock acquired and retired	(5)	(109)	(536)	—	(650)	—	(650)
Noncontrolling interests, net	—	—	—	—	—	(309)	(309)
Balance at December 31, 2022	$ 306	$ 6,206	$ 1,474	$ (131)	$ 7,855	$ 641	$ 8,496
Net income	—	—	1,382	—	1,382	356	1,738
Other comprehensive income (loss)	—	—	—	(3)	(3)	—	(3)
Share-based compensation	1	100	—	—	101	—	101
Dividends on common stock	—	—	(538)	—	(538)	—	(538)
Sale of Class A shares of Hess Midstream LP	—	158	—	—	158	175	333
Repurchase of Class B units of Hess Midstream Operations LP	—	31	—	—	31	(220)	(189)
Noncontrolling interests, net	—	—	—	—	—	(336)	(336)
Balance at December 31, 2023	$ 307	$ 6,495	$ 2,318	$ (134)	$ 8,986	$ 616	$ 9,602

See accompanying Notes to Consolidated Financial Statements.

1. Nature of Operations, Basis of Presentation and Summary of Accounting Policies

Unless the context indicates otherwise, references to "Hess", "the Corporation", "Registrant", "we", "us" and "our" refer to the consolidated business operations of Hess Corporation and its affiliates.

Nature of Business: Hess Corporation, incorporated in the State of Delaware in 1920, is a global E&P company engaged in exploration, development, production, transportation, purchase and sale of crude oil, natural gas liquids, and natural gas with production operations located in the United States (U.S.), Guyana, the Malaysia/Thailand Joint Development Area (JDA), and Malaysia. We conduct exploration activities primarily offshore Guyana, in the U.S. Gulf of Mexico, and offshore Suriname.

Our Midstream operating segment, which includes Hess Corporation's approximate 38% consolidated ownership interest in Hess Midstream LP at December 31, 2023 (see *Note 4, Hess Midstream LP*) provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGL; gathering, terminaling, loading and transporting crude oil and NGL; storing and terminaling propane, and water handling services primarily in the Bakken shale play in the Williston Basin area of North Dakota.

On October 22, 2023, we entered into an Agreement and Plan of Merger (the Merger Agreement) with Chevron Corporation (Chevron) and Yankee Merger Sub Inc. (Merger Subsidiary), a direct, wholly-owned subsidiary of Chevron. The Merger Agreement provides that, among other things and subject to the terms and conditions of the Merger Agreement, Merger Subsidiary will be merged with and into Hess, and Hess will be the surviving corporation in the Merger as a direct, wholly-owned subsidiary of Chevron (such transaction, the Merger). Under the terms of the Merger Agreement, if the Merger is completed, our stockholders will receive at the effective time of the Merger consideration consisting of 1.025 shares of Chevron common stock for each share of our common stock. The transaction is expected to close mid-2024, subject to shareholder and regulatory approvals and other closing conditions.

Basis of Presentation and Principles of Consolidation: The consolidated financial statements include the accounts of Hess Corporation and entities in which we own more than a 50% voting interest. We consolidate Hess Midstream LP, a variable interest entity, based on our conclusion that we have the power through Hess Corporation's approximate 38% consolidated ownership interest in Hess Midstream LP to direct those activities that most significantly impact the economic performance of Hess Midstream LP, and are obligated to absorb losses or have the right to receive benefits that could potentially be significant to Hess Midstream LP. Our undivided interests in unincorporated oil and gas E&P ventures are proportionately consolidated. Investments in affiliated companies, 20% to 50% owned and where we have the ability to influence the operating or financial decisions of the affiliate, are accounted for using the equity method.

Estimates and Assumptions: In preparing financial statements in conformity with GAAP, management makes estimates and assumptions that affect the reported amounts of assets and liabilities in the *Consolidated Balance Sheet* and revenues and expenses in the *Statement of Consolidated Income*. Actual results could differ from those estimates. Estimates made by management include oil and gas reserves, asset and other valuations, depreciable lives, post-retirement liabilities, legal and environmental obligations, asset retirement obligations and income taxes.

Revenue Recognition:

Exploration and Production

The E&P segment recognizes revenue from the sale of crude oil, NGL, and natural gas as performance obligations under contracts with customers are satisfied. Our responsibilities to deliver each unit of quantity of crude oil, NGL, and natural gas under these contracts represent separate, distinct performance obligations. These performance obligations are satisfied at the point in time control of each unit of quantity transfers to the customer. Generally, the control of each unit of quantity transfers to the customer upon the transfer of legal title at the point of physical delivery. Pricing is variable and is determined with reference to a particular market or pricing index, plus or minus adjustments reflecting quality or location differentials.

For long-term international natural gas contracts with ship-or-pay provisions, our obligation to stand-ready to provide a minimum volume over each commitment period represents separate, distinct performance obligations. Penalties owed against future deliveries of natural gas due to delivery of volumes below minimum delivery commitments are recognized as reductions to revenue in the commitment period when the shortfall occurs. Long-term international natural gas contracts may also contain take-or-pay provisions whereby the customer is required to pay for volumes not taken that are below minimum volume commitments, but the customer has certain make-up rights to receive shortfall volumes in subsequent periods. Shortfall payments received from customers when volumes purchased are below the minimum volume commitment are deferred upon receipt as a contract liability. Revenue is recognized at the earlier of when we deliver the make-up volumes in subsequent periods or when it becomes remote that the customer will exercise their make-up rights.

Certain crude oil, NGL, and natural gas volumes are purchased by Hess from third parties, including working interest partners and royalty owners in certain Hess-operated properties, before they are sold to customers. Where control over the crude oil, NGL, or natural gas transfers to Hess before the volumes are transferred to the customer, revenue and the associated cost of purchased volumes are presented on a gross basis in the *Statement of Consolidated Income* within *Sales and other operating revenues* and *Marketing, including purchased oil and gas*, respectively. Where control of crude oil, NGL, or natural gas is not transferred to Hess, revenue is presented net of the associated cost of purchased volumes within *Sales and other operating revenues* in the S*tatement of Consolidated Income*.

Contract Duration and Pricing:

Contracts with customers for the sale of U.S. crude oil, NGL, and natural gas primarily include those contracts that involve the short-term sale of volumes during a specified period, and those contracts that automatically renew on a periodic basis until either party cancels. We have certain long-term contracts with customers for the sale of U.S. natural gas and NGL that have remaining durations ranging from one to nine years.

Contracts with customers for the sale of international crude oil involve the short-term sale of volumes during a specified period. Pricing is determined with reference to a particular market or pricing index, plus or minus adjustments reflecting quality or location differentials, shortly after control of the volumes transfers to the customer. International contracts with customers for the sale of natural gas are in the form of natural gas sales agreements with government entities that have durations that are aligned with the durations of production sharing contracts or other contractual arrangements with host governments. Pricing for our natural gas sales agreements in North Malay Basin and Block A-18 of JDA are determined using contractual formulas that are based on the price of alternative fuels as obtained from price indices and other factors.

Contract Balances:

Our right to receive or collect payment from the customer is aligned with the timing of revenue recognition except in situations when we receive shortfall payments under contracts with take-or-pay provisions with customer make-up rights. Generally, we receive payments from customers on a monthly basis, shortly after the physical delivery of the crude oil, NGL, or natural gas. At December 31, 2023, there were no contract liabilities. At December 31, 2022, there were contract liabilities of $24 million resulting from a take-or-pay deficiency payment received in 2021 that was subject to a make-up period expiring in December 2023. During the year ended December 31, 2023, revenue of $24 million was recognized within *Sales and other operating revenues* that was included in the contract liability balance at December 31, 2022. At December 31, 2023 and 2022, there were no contract assets.

Transaction Price Allocated to Remaining Performance Obligations:

The transaction price allocated to our wholly unsatisfied performance obligations on uncompleted contracts is variable. Further, many of our contracts with customers have durations of less than twelve months. Accordingly, we have elected under the provisions of Accounting Standards Codification (ASC) 606, *Revenues from Contracts with Customers,* the exemption from disclosure of revenue recognizable in future periods as these performance obligations are satisfied.

Sales-based Taxes:

We exclude sales-based taxes that are collected from customers from the transaction price in our contracts with customers. Accordingly, revenue from contracts with customers is net of sales-based taxes that are collected from customers and remitted to taxing authorities.

Revenue from Non-customers:

In Guyana, the joint venture partners (Co-Venturers) to the Stabroek Block petroleum agreement are subject to the income tax laws of Guyana and remain primarily liable for income taxes due on the results of operations, resulting in recognition of income tax expense. Pursuant to the contractual arrangements of the petroleum agreement, a portion of gross production from the block, separate from the Co-Venturers' cost oil and profit oil entitlement, is used to satisfy the Co-Venturers' income tax liability. This portion of gross production, referred to as tax barrels, is included in our reported production volumes and is recognized as sales revenue from non-customers.

Midstream

The Midstream segment earns substantially all of its revenues by charging fees for gathering, compressing and processing natural gas and fractionating NGLs; gathering, terminaling, loading and transporting crude oil and NGLs; storing and terminaling propane; and gathering and disposing produced water. Effective January 1, 2014, certain subsidiaries of Hess Midstream LP entered into (i) gas gathering, (ii) crude oil gathering, (iii) gas processing and fractionation, (iv) storage services and (v) terminaling and export services commercial agreements with certain subsidiaries of Hess, each generally with an initial ten-year term which could be extended for an additional ten-year term at the unilateral right of the Hess Midstream LP subsidiaries. These Hess Midstream LP subsidiaries exercised their right to extend the terms of the gas gathering, crude oil gathering, gas processing and fractionation, storage services, and terminaling and export services commercial agreements for the secondary term effective January 1, 2024 through December 31, 2033. Effective January 1, 2019, a subsidiary of Hess Midstream LP entered into water gathering and disposal services agreements with a subsidiary of Hess. These agreements also provide Hess Midstream the capacity to provide concurrent use of these services directly to third parties.

The Midstream segment's responsibility to provide each service for each year under each of the commercial agreements are considered separate, distinct performance obligations. Revenue is recognized over-time for each performance obligation as services are rendered using the output method, measured using the amount of volumes serviced during the period. The commercial agreements contain minimum volume commitments which fluctuate based on nominations covering substantially all of our E&P segment's existing and future owned or controlled production in the Bakken and projected third-party volumes owned or controlled by our E&P segment through dedicated third-party contracts. Minimum volume commitments are equal to 80% of the nominations and apply on a three-year rolling basis such that they are set for the three years following the most recent nomination. As the minimum volume commitments are subject to fluctuation, and these commercial agreements contain fee inflation escalators and fee recalculation mechanisms, substantially all of the transaction price is variable at inception of each of the commercial agreements. The Midstream segment has elected the practical expedient under the provisions of Accounting Standards Codification (ASC) 606*, Revenue from Contracts with Customers* to recognize revenue in the amount it is entitled to invoice.

If the volumes delivered are less than the applicable minimum volume commitments under the commercial agreements during any quarter, the applicable Hess subsidiary is obligated to pay a shortfall fee equal to the volume deficiency multiplied by the related gathering, processing and/or terminaling fee. The Midstream segment's responsibility to stand-ready to service a minimum volume over each quarterly commitment period represents a separate, distinct performance obligation. During the initial term of each commercial agreement, volume deficiencies are measured quarterly and recognized as revenue in the same period, as any associated shortfall payments are not subject to future reduction or offset. During the secondary term of each commercial agreement, the applicable Hess subsidiary will be entitled to receive a credit, calculated in barrels or Mcf, as applicable, with respect to the amount of any shortfall fee paid. Such Hess subsidiary may apply the credit against the fees payable for any volumes delivered under the applicable agreement in excess of the nominated volumes up to four quarters after the credit is earned. Unused credits will be recognized as revenue when it becomes remote that such credits will be utilized. No credits will be provided with respect to crude oil terminaling services under the terminaling and export services commercial agreement or water handling services under the water gathering and disposal services agreements.

All revenues, receivables, and contract balances arising from the commercial agreements between the Midstream segment and the Hess subsidiaries that are the counterparty to the commercial agreements are eliminated upon consolidation.

Exploration and Development Costs: E&P activities are accounted for using the successful efforts method. Costs of acquiring unproved and proved oil and gas leasehold acreage, including lease bonuses, brokers' fees and other related costs are capitalized. Annual lease rentals, exploration expenses and exploratory dry hole costs are expensed as incurred. Costs of drilling and equipping productive wells, including development dry holes, and related production facilities are capitalized.

The costs of exploratory wells that find oil and gas reserves are capitalized pending determination of whether proved reserves have been found. Exploratory drilling costs remain capitalized after drilling is completed if (1) the well has found a sufficient quantity of reserves to justify completion as a producing well and (2) sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. If either of those criteria is not met, or if there is substantial doubt about the economic or operational viability of a project, the capitalized well costs are charged to expense. Indicators of sufficient progress in assessing reserves and the economic and operating viability of a project include commitment of project personnel, active negotiations for sales contracts with customers, negotiations with governments, operators and contractors, firm plans for additional drilling and other factors.

Depreciation, Depletion and Amortization: We record depletion expense for acquisition costs of proved properties using the units of production method over proved oil and gas reserves. Depreciation and depletion expense for oil and gas production facilities and wells is calculated using the units of production method over proved developed oil and gas reserves. Provisions for impairment of undeveloped oil and gas leases are based on periodic evaluations and other factors. Depreciation of all other plant and equipment is determined on the straight-line method based on estimated useful lives.

Capitalized Interest: Interest from external borrowings is capitalized on material projects using the weighted average cost of outstanding borrowings until the project is substantially complete and ready for its intended use, which for oil and gas assets is at first production from the field. Capitalized interest is depreciated in the same manner as the depreciation of the underlying assets.

Impairment of Long-lived Assets: We review long-lived assets, including oil and gas fields, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts of the long-lived assets are not expected to be recovered by estimated undiscounted future net cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is measured based on the estimated fair value of the assets generally determined by discounting anticipated future net cash flows, an income valuation approach, or by a market-based valuation approach, which are Level 3 fair value measurements.

In the case of oil and gas fields, the present value of future net cash flows is based on management's best estimate of future prices, which is determined with reference to recent historical prices and published forward prices, applied to projected production volumes and discounted at a risk-adjusted rate. The projected production volumes represent reserves, including probable reserves, expected to be produced based on a projected amount of capital expenditures. The production volumes, prices and timing of production are consistent with internal projections and other externally reported information. Oil and gas prices used for determining asset impairment will generally differ from those used in the standardized measure of discounted future net cash flows reported in *Supplementary Oil and Gas Data*, since the standardized measure requires the use of historical twelve-month average prices.

Impairment of Goodwill: Goodwill is tested for impairment annually on October 1st or when events or circumstances indicate it is more likely than not that the fair value of the reporting unit is less than its carrying value, including goodwill. If the fair value of the reporting unit exceeds its carrying value, goodwill is not impaired. If the carrying value of the reporting unit exceeds its fair value, an impairment loss would be recorded for the excess of the carrying value over fair value, limited by the amount of goodwill allocated to the reporting unit. At December 31, 2023, goodwill of $360 million relates to the Midstream operating segment.

Cash and Cash Equivalents: Cash and cash equivalents primarily comprises cash on hand and on deposit, as well as highly liquid investments that are readily convertible into cash and have maturities of three months or less when acquired.

Inventories: Produced and unsold crude oil and NGL are valued at the lower of cost or net realizable value. Cost is determined using the average cost of production plus any transport cost incurred in bringing the volumes to their present location. Materials and supplies are valued at cost. Obsolete or surplus materials identified during periodic reviews are valued at the lower of cost or estimated net realizable value.

Leases: We determine if an arrangement is a lease at inception by evaluating whether the contract conveys the right to control an identified asset during the period of use. ROU assets represent our right to use an identified asset for the lease term and lease obligations represent our obligation to make payments as set forth in the lease arrangement. ROU assets and lease liabilities are recognized in the *Consolidated Balance Sheet* as operating leases or finance leases at the commencement date based on the present value of the minimum lease payments over the lease term. Where the implicit discount rate in a lease is not readily determinable, we use our incremental borrowing rate based on information available at the commencement date for determining the present value of the minimum lease payments. The lease term used in measurement of our lease obligations includes options to extend or terminate the lease when, in our judgment, it is reasonably certain that we will exercise that option. Variable lease payments that depend on an index or a rate are included in the measurement of lease obligations using the index or rate at the commencement date. Variable lease payments that vary because of changes in facts or circumstances after the commencement date of the lease are not included in the minimum lease payments used to measure lease obligations. We have agreements that include financial obligations for lease and nonlease components. For purposes of measuring lease obligations, we have elected not to separate nonlease components from lease components for the following classes of assets: drilling rigs, office space, offshore vessels, and aircraft. We apply a portfolio approach to account for operating lease ROU assets and liabilities for certain vehicles, railcars, field equipment and office equipment leases.

Finance lease cost is recognized as amortization of the ROU asset and interest expense on the lease liability. Operating lease cost is generally recognized on a straight-line basis. Operating lease costs for drilling rigs used to drill development wells and successful exploration wells are capitalized. Operating lease cost for other ROU assets used in oil and gas producing activities are either capitalized or expensed based on the nature of operation for which the ROU asset is utilized.

Leases with an initial term of 12 months or less are not recorded on the balance sheet as permitted under ASC 842, *Leases*. We recognize lease cost for short-term leases on a straight-line basis over the term of the lease. Some of our leases with initial terms of 12 months or less include one or more options to renew. The renewal option is at our sole discretion and is not included in the lease term for measurement of the lease obligation unless we are reasonably certain at the commencement date of the lease, to renew the lease.

Income Taxes: Deferred income taxes are determined using the liability method. We have net operating loss carryforwards or credit carryforwards in multiple jurisdictions and have recognized deferred tax assets for those losses and credits. Additionally, we have deferred tax assets due to temporary differences between the book basis and tax basis of certain assets and liabilities. Regular assessments are made as to the likelihood of those deferred tax assets being realized. If, when tested under the relevant accounting standards, it is more likely than not that some or all of the deferred tax assets will not be realized, a valuation allowance is established to reduce the deferred tax assets to the amount that is expected to be realized. The accounting standards require the evaluation of all available positive and negative evidence giving weight based on the evidence's relative objectivity. In evaluating potential sources of positive evidence, we consider the reversal of taxable temporary differences, taxable income in carryback and carryforward periods, the availability of tax planning strategies, the existence of appreciated assets, estimates of future taxable income, and other factors. In evaluating potential sources of negative evidence, we consider a cumulative loss in recent years, any history of operating losses or tax credit carryforwards expiring unused, losses expected in early future years, unsettled circumstances that, if unfavorably resolved, would adversely affect future operations and profit levels on a continuing basis in future years, and any carryback or carryforward period so brief that a significant deductible temporary difference expected to reverse in a single year would limit realization of tax benefits. We assign cumulative historical losses significant weight in the evaluation of realizability relative to more subjective evidence such as forecasts of future income. In addition, we recognize the financial statement effect of a tax position only when management believes that it is more likely than not, that based on the technical merits, the position will be sustained upon examination. We are not indefinitely reinvested with respect to the book in excess of tax basis in the investment in our foreign subsidiaries. Because of U.S. tax reform we expect that the future reversal of such temporary differences will occur free of material taxation. We classify interest and penalties associated with uncertain tax positions as income tax expense. We account for the U.S. tax effect of global intangible low-taxed income earned by foreign subsidiaries in the period that such income is earned. We utilize the aggregate approach for releasing disproportionate income tax effects from *Accumulated other comprehensive income (loss)*.

Asset Retirement Obligations: We have legal obligations to remove and dismantle long-lived assets and to restore land or the seabed at certain E&P locations. We initially recognize a liability for the fair value of legally required asset retirement obligations in the period in which the retirement obligations are incurred and capitalize the associated asset retirement costs as part of the carrying amount of the long-lived assets. In subsequent periods, the liability is accreted over the useful life of the related asset, and the capitalized asset retirement costs are depreciated over proved developed oil and gas reserves using the units of production method or the useful life of the related asset. Fair value is determined by applying a credit adjusted risk-free rate to the undiscounted expected future abandonment expenditures. Changes in estimates prior to settlement result in adjustments to both the liability and related asset values, unless the field has ceased production, in which case changes are recognized in the *Statement of Consolidated Income*.

We measure asset retirement obligations based on the requirements of existing laws and regulations in accordance with ASC 410-20, *Asset Retirement Obligations*. Laws and regulations associated with the scope and timing for the abandonment of oil and gas wells, facilities and equipment could change which could increase the cost of our abandonment obligations. In addition, we may be required to assume abandonment obligations for certain divested assets in the event the current or future owners of facilities previously owned by us are unable to perform, whether due to bankruptcy or otherwise.

Retirement Plans: We recognize the funded status of defined benefit postretirement plans in the *Consolidated Balance Sheet*. The funded status is measured as the difference between the fair value of plan assets and the projected benefit obligation. We recognize the net changes in the funded status of these plans as a component of *Other Comprehensive Income (Loss)* in the year in which such changes occur. Actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the market value of plan assets are amortized over the average remaining service period of active employees or the remaining average expected life if a plan's participants are predominantly inactive.

Derivatives: We utilize derivative instruments for financial risk management activities. In these activities, we may use futures, forwards, options and swaps, individually or in combination, to mitigate our exposure to fluctuations in prices of crude oil and natural gas, as well as changes in interest and foreign currency exchange rates.

All derivative instruments are recorded at fair value in the *Consolidated Balance Sheet*. Our policy for recognizing the changes in fair value of derivatives varies based on the designation of the derivative. The changes in fair value of derivatives that are not designated as hedges are recognized currently in earnings. Derivatives may be designated as hedges of expected future cash flows or forecasted transactions (cash flow hedges), or hedges of changes in fair value of recognized assets and liabilities or of unrecognized firm commitments (fair value hedges). Changes in fair value of derivatives that are designated as cash flow hedges are recorded as a component of *Other Comprehensive Income (Loss)*. Amounts included in *Accumulated Other Comprehensive Income (Loss)* for cash flow hedges are reclassified into earnings in the same period that the hedged item is recognized in earnings. Changes in fair value of derivatives designated as fair value hedges are recognized currently in earnings. The change in fair value of the related hedged item is recorded as an adjustment to its carrying amount and recognized currently in earnings.

Fair Value Measurements: We use various valuation approaches in determining fair value for financial instruments, including the market and income approaches. Our fair value measurements also include non-performance risk and time value of money considerations. Counterparty credit is considered for financial assets, and our credit is considered for financial liabilities. We also record certain nonfinancial assets and liabilities at fair value when required by GAAP. These fair value measurements are recorded in connection with business combinations, qualifying nonmonetary exchanges, the initial recognition of asset retirement obligations and any impairment of long-lived assets, equity method investments, goodwill or other indefinite-lived intangible assets, such as environmental credits. We determine fair value in accordance with the fair value measurements accounting standard which established a hierarchy for the inputs used to measure fair value based on the source of the inputs, which generally range from quoted prices for identical instruments in a principal trading market (Level 1) to estimates determined using related market data (Level 3), including discounted cash flows and other unobservable data. Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. When Level 1 inputs are available within a particular market, those inputs are selected for determination of fair value over Level 2 or 3 inputs in the same market. Multiple inputs may be used to measure fair value; however, the level assigned to a fair value measurement is based on the lowest significant input level within this fair value hierarchy.

Details on the methods and assumptions used to determine the fair values are as follows:

Fair value measurements based on Level 1 inputs: Measurements that are most observable are based on quoted prices of identical instruments obtained from the principal markets in which they are traded. Closing prices are both readily available and representative of fair value. Market transactions occur with sufficient frequency and volume to assure liquidity.

Fair value measurements based on Level 2 inputs: Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. Measurements based on Level 2 inputs include over-the-counter derivative instruments that are priced on an exchange-traded curve but have contractual terms that are not identical to exchange-traded contracts.

Fair value measurements based on Level 3 inputs: Measurements that are least observable are estimated from related market data, determined from sources with little or no market activity for comparable contracts or are positions with longer durations. Fair values determined using discounted cash flows and other unobservable data are also classified as Level 3.

Netting of Financial Instruments: We generally enter into master netting arrangements to mitigate legal and counterparty credit risk. Master netting arrangements are generally accepted overarching master contracts that govern all individual transactions with the same counterparty entity as a single legally enforceable agreement. The U.S. Bankruptcy Code provides for the enforcement of certain termination and netting rights under certain types of contracts upon the bankruptcy filing of a counterparty, commonly known as the “safe harbor” provisions. If a master netting arrangement provides for termination and netting upon the counterparty’s bankruptcy, these rights are generally enforceable with respect to “safe harbor” transactions. If these arrangements provide the right of offset and our intent and practice is to offset amounts in the case of such a termination, our policy is to record the fair value of derivative assets and liabilities on a net basis. In the normal course of business, we rely on legal and credit risk mitigation clauses providing for adequate credit assurance as well as close-out netting, including two-party netting and single counterparty multilateral netting. As applied to us, “two-party netting” is the right to net amounts owing under safe harbor transactions between a single defaulting counterparty entity and a single Hess entity, and “single counterparty multilateral netting” is the right to net amounts owing under safe harbor transactions among a single defaulting counterparty entity and multiple Hess entities. We are reasonably assured that these netting rights would be upheld in a bankruptcy proceeding in the U.S. in which the defaulting counterparty is a debtor under the U.S. Bankruptcy Code.

Share-based Compensation: We account for share-based compensation based on the fair value of the award on the date of grant. The fair value of all share-based compensation is recognized over the requisite service period for the entire award, whether the award was granted with ratable or cliff vesting terms, net of actual forfeitures. We estimate fair value at the date of grant using a Black-Scholes valuation model for employee stock options and a Monte Carlo simulation model for performance share units (PSUs). Fair value of restricted stock is based on the market value of the underlying shares at the date of grant.

Foreign Currency Remeasurement: The U.S. Dollar is the functional currency (primary currency in which business is conducted) for our foreign operations. Adjustments resulting from remeasuring monetary assets and liabilities that are denominated in a currency other than the functional currency are recorded in *Other, net* in the *Statement of Consolidated Income*.

Maintenance and Repairs: Maintenance and repairs are expensed as incurred. Capital improvements are recorded as additions in *Property, plant and equipment*.

Environmental Expenditures: We accrue and expense the undiscounted environmental costs necessary to remediate existing conditions related to past operations when the future costs are probable and reasonably estimable. At year-end 2023, our reserve for estimated remediation liabilities was approximately $50 million. Environmental expenditures that increase the life or efficiency of property or reduce or prevent future adverse impacts to the environment are capitalized.

Environmental Credits: Carbon credits and renewable energy certificates are purchased to fulfill voluntary emissions reduction targets and are classified as indefinite-lived intangible assets. They are expensed when retired to offset emissions and are tested for impairment annually on October 1st, or when events or circumstances indicate it is more likely than not that fair value is less than carrying value. If the carrying value exceeds fair value, an impairment loss would be recorded for the excess of the carrying value over fair value.

In response to feedback from constituents and the staff’s related research and analysis, the Financial Accounting Standards Board (FASB) added a project to its technical agenda on May 25, 2022 to address the accounting for environmental credits due to a lack of existing guidance for accounting for environmental credits. Our environmental credits fall within the scope of this project. Included among the tentative decisions made by the FASB on January 31, 2024, is a prohibition against capitalizing the cost of environmental credits that will not be sold or used to settle environmental credit obligations. In 2023, we purchased $75 million REDD+ carbon credits (2022: $75 million, 2021: $0 million) under a long-term agreement with the Government of Guyana that was executed in December 2022 in order to support ongoing carbon emissions reduction efforts by the Corporation. The carbon credits acquired by us are registered on the ART Registry, an over-the-counter registry, and can be sold to third parties or retired to offset emissions. These amounts would have been expensed in the period of purchase, instead of capitalized as indefinite-lived intangible assets, if the prohibition per the tentative decision above were applied. At December 31, 2023, the carrying value of our carbon credits of

$150 million (2022: $75 million) is included in non-current *Other assets* in the *Consolidated Balance Sheet*. All renewable energy certificates were retired and expensed in the period of purchase.

New Accounting Pronouncements:

In November 2023, the FASB issued Accounting Standards Update (ASU) No. 2023-07, *Improvements to Reportable Segments Disclosures*. The ASU improves reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. The ASU does not change how an entity identifies its operating segments. The ASU is effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024. Early adoption is permitted. We are currently assessing the impact of adopting the ASU on our consolidated financial statements.

In December 2023, the FASB issued ASU No. 2023-09, *Improvements to Income Tax Disclosures*, which enhances the disclosure requirements within ASC Topic 740. The ASU requires, among other disclosures, greater disaggregation of information and the use of certain categories in the rate reconciliation, and the disaggregation of income taxes paid by jurisdiction. The ASU is effective for annual periods beginning after December 15, 2024. Early adoption is permitted. We are currently assessing the impact of adopting this ASU on our consolidated financial statements.

2. Inventories

Inventories at December 31 were as follows:

	2023	**2022**
	(In millions)	
Crude oil and natural gas liquids	**$ 72**	$ 63
Materials and supplies	**232**	154
Total Inventories	**$ 304**	$ 217

3. Property, Plant and Equipment

Property, plant and equipment at December 31 were as follows:

	2023	**2022**
	(In millions)	
Exploration and Production		
Unproved properties	**$ 103**	$ 149
Proved properties	**2,660**	2,660
Wells, equipment and related facilities	**29,159**	25,182
	31,922	27,991
Midstream	**4,819**	4,571
Corporate and Other	**30**	30
Total — at cost	**36,771**	32,592
Less: Reserves for depreciation, depletion, amortization and lease impairment	**19,339**	17,494
Property, Plant and Equipment — Net	**$ 17,432**	$ 15,098

Capitalized Exploratory Well Costs: The following table discloses the amount of capitalized exploratory well costs pending determination of proved reserves at December 31 and the changes therein during the respective years:

	2023	**2022**	**2021**
		(In millions)	
Balance at January 1	**$ 886**	$ 681	$ 459
Additions to capitalized exploratory well costs pending the determination of proved reserves	**257**	298	222
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(133)**	(93)	—
Capitalized exploratory well costs charged to expense	**(58)**	—	—
Balance at December 31	**$ 952**	$ 886	$ 681
Number of Wells at December 31	**43**	43	35

During the three years ended December 31, 2023, additions to capitalized exploratory well costs primarily related to drilling at the Stabroek Block (Hess 30%), offshore Guyana. At December 31, 2023, 36 exploration and appraisal wells on the Stabroek Block, with a total cost of $841 million, were capitalized pending determination of proved reserves. Other additions to capitalized exploratory well costs in 2023 include the Pickerel-1 exploration well (Hess 100%) in the Gulf of Mexico on Mississippi Canyon Block 727.

Other additions to capitalized exploratory wells costs in 2022 include the Huron-1 well (Hess 40%) in the Gulf of Mexico, and the Zanderij-1 well on Block 42 (Hess 33%), offshore Suriname.

Reclassifications to wells, facilities and equipment based on the determination of proved reserves in 2023 resulted from the sanction of the Uaru Field development, the fifth sanctioned project on the Stabroek Block, and the Pickerel-1 exploration well in the Gulf of Mexico. In 2022, reclassifications to wells, facilities and equipment resulted from the sanction of the Yellowtail Field development, the fourth sanctioned project on the Stabroek Block.

Capitalized exploratory well costs charged to expense in 2023 of $58 million primarily relate to the Huron-1 well in the Gulf of Mexico. In the fourth quarter of 2023, we, along with our partners, decided not to appraise the discovery given other available opportunities and the limited time remaining on the leases. The preceding table excludes well costs incurred and expensed during 2023 of $89 million (2022: $56 million; 2021: $11 million).

Exploratory well costs capitalized for greater than one year following completion of drilling were $728 million at December 31, 2023, separated by year of completion as follows (in millions):

2022	$ 261
2021	162
2020	8
2019	139
2018 and prior	158
	$ 728

Guyana: 87% of the capitalized well costs in excess of one year relate to successful exploration and appraisal wells where hydrocarbons were encountered on the Stabroek Block (Hess 30%). In October 2023, the operator submitted a plan for the Whiptail development project, the sixth development project on the Stabroek Block, to the Government of Guyana for approval. The operator also plans further appraisal drilling on the block and is conducting pre-development planning for additional phases of development.

Suriname.: 6% of the capitalized well costs in excess of one year relates to the Zanderij-1 well on Block 42 (Hess 33%). Exploration and appraisal activities are ongoing.

JDA: 5% of the capitalized well costs in excess of one year relates to the JDA (Hess 50%) in the Gulf of Thailand, where hydrocarbons were encountered in three successful exploration wells drilled in the western part of Block A-18. The operator has submitted a development plan concept to the regulator to facilitate ongoing commercial negotiations for an extension of the existing gas sales contract to include development of the western part of the block.

Malaysia: 2% of the capitalized well costs in excess of one year relates to North Malay Basin (Hess 50%), offshore Peninsular Malaysia, where hydrocarbons were encountered in two successful exploration wells. Pre-development studies are ongoing.

4. Hess Midstream LP

Hess Midstream LP, a variable interest entity, has an "Up-C" organizational structure. We have an approximate 38% consolidated ownership interest at December 31, 2023 in Hess Midstream LP on an as-exchanged basis, primarily through our ownership of Class B units in Hess Midstream Operations LP (HESM Opco), the operating subsidiary of Hess Midstream LP, which are exchangeable into Class A shares of Hess Midstream LP on a one-for-one basis. An affiliate of Global Infrastructure Partners (GIP) owns an approximate 32% consolidated interest in Hess Midstream LP at December 31, 2023, on an as-exchanged basis, primarily through its ownership of Class B units in HESM Opco, and the public owns an approximate 30% consolidated interest in Hess Midstream LP at December 31, 2023, through the ownership of Class A shares of Hess Midstream LP. We have concluded that we are the primary beneficiary of the variable interest entity since we have the power to direct those activities that most significantly impact the economic performance of Hess Midstream LP, and are obligated to absorb losses or have the right to receive benefits that could potentially be significant to Hess Midstream LP. This conclusion was based on a qualitative analysis that considered Hess Midstream LP's governance structure, the commercial agreements between Hess Midstream LP and us, and the voting rights established between the members.

In 2021, Hess Midstream LP completed two underwritten public equity offerings of an aggregate of approximately 15.5 million Hess Midstream LP Class A shares held by affiliates of Hess and GIP. Hess received an aggregate of $178 million of net proceeds from these transactions. These transactions, in aggregate, resulted in an increase in *Capital in excess of par* and *Noncontrolling interests* of $152 million and $103 million, respectively. The aggregate increase to *Noncontrolling interests* of $103 million is comprised of $26 million resulting from the changes in ownership interests and $77 million from increases to deferred tax assets resulting from step-ups in the tax basis of Hess Midstream LP's investment in HESM Opco.

In 2021, HESM Opco repurchased 31.25 million HESM Opco Class B units held by affiliates of Hess and GIP for $750 million in a single transaction. HESM Opco issued $750 million in aggregate principal amount of 4.250% fixed-rate senior unsecured notes due

2030 in a private offering to finance the repurchase. The transaction resulted in an increase in *Capital in excess of par* and a decrease in *Noncontrolling interests* of $28 million, and an increase in deferred tax assets and *Noncontrolling interests* of $15 million resulting from an adjustment in the carrying value of Hess Midstream LP's investment in HESM Opco without a corresponding adjustment in the tax basis. The $375 million paid to GIP reduced *Noncontrolling interests*.

In 2022, Hess Midstream LP completed a single underwritten public equity offering of approximately 10.2 million Hess Midstream LP Class A shares held by affiliates of Hess and GIP. Hess received net proceeds of $146 million from the transaction. The transaction resulted in an increase in *Capital in excess of par* and *Noncontrolling interests* of $130 million and $88 million, respectively. The increase to *Noncontrolling interests* of $88 million is comprised of $16 million resulting from the change in ownership interests and $72 million from an increase to deferred tax assets resulting from a step-up in the tax basis of Hess Midstream LP's investment in HESM Opco.

In 2022, HESM Opco repurchased approximately 13.6 million HESM Opco Class B units held by affiliates of Hess and GIP for $400 million in a single transaction. HESM Opco issued $400 million in aggregate principal amount of 5.500% fixed-rate senior unsecured notes due 2030 in a private offering to repay borrowings under its revolving credit facility used to finance the repurchase. The transaction resulted in an increase in *Capital in excess of par* and a decrease in *Noncontrolling interests* of $32 million, and an increase in deferred tax assets and *Noncontrolling interests* of $17 million resulting from an adjustment in the carrying value of Hess Midstream LP's investment in HESM Opco without a corresponding adjustment in the tax basis. The $200 million paid to GIP reduced *Noncontrolling interests*.

In May 2023, Hess Midstream LP completed an underwritten public equity offering of approximately 12.8 million Hess Midstream LP Class A shares held by affiliates of Hess and GIP. Hess received $167 million of net proceeds from this transaction. This transaction resulted in an increase in *Capital in excess of par* and *Noncontrolling interests* of $158 million and $93 million, respectively. The increase to *Noncontrolling interests* of $93 million is comprised of $9 million resulting from the change in ownership interests and $84 million from an increase to deferred tax assets resulting from a step-up in the tax basis of Hess Midstream LP's investment in HESM Opco. In August 2023, Hess Midstream LP completed an underwritten public equity offering of 11.5 million Class A shares held by an affiliate of GIP. Hess did not participate in this transaction and did not receive any proceeds. There was no change in Hess' ownership interest in Hess Midstream LP on a consolidated basis and accordingly, there was no impact to the balance of *Noncontrolling interests*. However, the transaction did result in an increase to deferred tax assets of $82 million, with the offset recorded to *Noncontrolling interests,* due to a step-up in the tax basis of Hess Midstream LP's investment in HESM Opco.

In 2023, HESM Opco repurchased an aggregate of approximately 13.6 million HESM Opco Class B units in multiple transactions from affiliates of Hess and GIP for total proceeds of $400 million. The unit repurchases were financed by borrowings under HESM Opco's revolving credit facility. The unit repurchases, in aggregate, resulted in an increase in *Capital in excess of par* and a decrease in *Noncontrolling interests* of $31 million, and an increase in deferred tax assets and *Noncontrolling interests* of $23 million resulting from adjustments in the carrying value of Hess Midstream LP's investment in HESM Opco without corresponding adjustments in the tax basis. The aggregate proceeds paid to GIP of $212 million reduced *Noncontrolling interests*. Hess participated in all the HESM Opco Class B unit repurchase transactions in 2023 on a 50/50 basis with GIP with the exception of the HESM Opco Class B unit repurchase transaction in November 2023. Hess and GIP received $38 million and $62 million, respectively, of the total proceeds of $100 million. There was no change in Hess' ownership interest in Hess Midstream LP on a consolidated basis as a result of this transaction and accordingly, there was no impact to the balance of *Noncontrolling interests.* However, the transaction did result in an increase to deferred tax assets of $7 million, with the offset recorded to *Noncontrolling interests*, as a result of an adjustment in the carrying value of Hess Midstream LP's investment in HESM Opco without a corresponding adjustment in the tax basis.

At December 31, 2023, Hess Midstream LP liabilities totaling $3,385 million (2022: $3,027 million) are on a nonrecourse basis to Hess Corporation, while Hess Midstream LP assets available to settle the obligations of Hess Midstream LP included cash and cash equivalents totaling $5 million (2022: $3 million), property, plant and equipment, net totaling $3,229 million (2022: $3,173 million) and the equity-method investment in Little Missouri 4 (LM4) of $90 million (2022: $94 million).

LM4 is a 200 million standard cubic feet per day gas processing plant located south of the Missouri River in McKenzie County, North Dakota, that was constructed as part of a 50/50 joint venture between Hess Midstream LP and Targa Resources Corp. Hess Midstream LP has a natural gas processing agreement with LM4 under which it pays a processing fee and reimburses LM4 for its proportionate share of electricity costs. In 2023, processing fees were $24 million (2022: $21 million; 2021: $28 million) and are included in *Operating costs and expenses* in the *Statement of Consolidated Income*.

5. Accrued Liabilities

The following table provides detail of our accrued liabilities at December 31:

	2023	2022
	(In millions)	
Accrued capital expenditures	**$ 670**	$ 499
Accrued operating and marketing expenditures	**593**	522
Accrued compensation and benefits	**193**	132
Accrued payments to royalty and working interest owners	**178**	201
Current portion of asset retirement obligations	**160**	207
Accrued interest on debt	**144**	143
Other accruals	**164**	136
Total Accrued Liabilities	**$ 2,102**	$ 1,840

6. Leases

Operating and finance lease obligations at December 31 included in the *Consolidated Balance Sheet* were as follows:

	Operating Leases		Finance Leases	
	2023	2022	2023	2022
	(In millions)			
Right-of-use assets — net (a)	**$ 720**	$ 570	**$ 108**	$ 126
Lease obligations:				
Current	**$ 347**	$ 200	**$ 23**	$ 21
Long-term	**459**	469	**156**	179
Total lease obligations	**$ 806**	$ 669	**$ 179**	$ 200

(a) At December 31, 2023, finance lease ROU assets had a cost of $212 million (2022: $212 million) and accumulated amortization of $104 million (2022: $86 million).

Lease obligations represent 100% of the present value of future minimum lease payments in the lease arrangement. Where we have contracted directly with a lessor in our role as operator of an unincorporated oil and gas venture, we bill our partners their proportionate share for reimbursements as payments under lease agreements become due pursuant to the terms of our joint operating and other agreements.

The nature of our leasing arrangements at December 31, 2023 was as follows:

Operating leases: In the normal course of business, we primarily lease drilling rigs, equipment, logistical assets (offshore vessels, aircraft, and shorebases), and office space.

Finance leases: In 2018, we entered into a sale and lease-back arrangement for a floating storage and offloading vessel (FSO) to handle produced condensate at North Malay Basin, offshore Peninsular Malaysia. At December 31, 2023, the remaining lease term for the FSO was 9.8 years.

Maturities of lease obligations at December 31, 2023 were as follows:

	Operating Leases	Finance Leases
	(In millions)	
2024	$ 377	$ 36
2025	197	36
2026	89	31
2027	48	22
2028	22	23
Remaining years	165	99
Total lease payments	898	247
Less: Imputed interest	(92)	(68)
Total lease obligations	$ 806	$ 179

The following information relates to the operating and finance leases at December 31:

	Operating Leases		Finance Leases	
	2023	2022	2023	2022
Weighted average remaining lease term	**5.0 years**	6.8 years	**9.8 years**	10.8 years
Range of remaining lease terms	**0.1 - 12.5 years**	0.3 - 13.5 years	**9.8 years**	10.8 years
Weighted average discount rate	**5.1%**	4.5%	**7.9%**	7.9%

The components of lease costs were as follows:

	2023	2022	2021
	(In millions)		
Operating lease cost (a)	**$ 241**	$ 114	$ 88
Finance lease cost:			
Amortization of leased assets	**18**	18	24
Interest on lease obligations	**15**	18	18
Short-term lease cost (b)	**294**	311	137
Variable lease cost (c)	**67**	33	21
Sublease income (d)	**(19)**	(18)	(17)
Total lease cost	**$ 616**	$ 476	$ 271

(a) Operating lease cost in 2023 included a drilling rig at North Malay Basin used for a 15 well development drilling program spanning 2023 and 2024, and offshore support vessels in the Gulf of Mexico.

(b) Short-term lease cost is primarily attributable to equipment used in global exploration, development, production, and crude oil marketing activities. Future short-term lease costs will vary based on activity levels of our operated assets. In 2023 and 2022, short-term lease cost included drilling rigs and offshore support vessels used primarily for exploration and abandonment activities in the Gulf of Mexico and workover rigs for maintenance activities in the Bakken.

(c) Variable lease costs for drilling rigs result from differences in the minimum rate and the actual usage of the ROU asset during the lease period. Variable lease costs for logistical assets result from differences in stated monthly rates and total charges reflecting the actual usage of the ROU asset during the lease period. Variable lease costs for our office leases represent common area maintenance charges which have not been separated from lease components.

(d) We sublease certain of our office space to third parties under our head lease.

The above lease costs represent 100% of the lease payments due for the period, including where we as operator have contracted directly with suppliers. As the payments under lease agreements where we are operator become due, we bill our partners their proportionate share for reimbursement pursuant to the terms of our joint operating agreements. Reimbursements are not reflected in the table above. Certain lease costs above associated with exploration and development activities are included in capital expenditures.

Supplemental cash flow information related to leases were as follows:

	Operating Leases			Finance Leases		
	2023	2022	2021	2023	2022	2021
	(In millions)					
Cash paid for amounts included in the measurement of lease obligations:						
Operating cash flows (a)	**$ 254**	$ 126	$ 87	**$ 15**	$ 18	$ 18
Financing cash flows (a)	**—**	—	—	**21**	19	18
Noncash transactions:						
Leased assets recognized for new lease obligations incurred (b)	**267**	294	12	**—**	—	—
Changes in leased assets and lease obligations due to lease modifications (c)	**97**	16	29	**—**	—	—

(a) Amounts represent gross lease payments before any recovery from partners.

(b) In 2023, primarily related to leases for a drilling rig and offshore support vessels in the Gulf of Mexico. In 2022, primarily related to leases for drilling rigs in the Bakken and at North Malay Basin.

(c) In 2023, primarily related to reassessments of the lease terms for a drilling rig at North Malay Basin, and offshore support vessels and aircraft in the Gulf of Mexico.

7. Debt

Total debt at December 31 consisted of the following:

	2023	2022
	(In millions)	
Debt – Hess Corporation:		
Senior unsecured fixed-rate public notes:		
3.500% due 2024	**$ 300**	$ 300
4.300% due 2027	**997**	996
7.875% due 2029	**465**	464
7.300% due 2031	**629**	629
7.125% due 2033	**537**	537
6.000% due 2040	**743**	742
5.600% due 2041	**1,238**	1,237
5.800% due 2047	**495**	494
Total senior unsecured fixed-rate public notes	**5,404**	5,399
Fair value adjustments – interest rate hedging	**(2)**	(4)
Total Debt – Hess Corporation	**$ 5,402**	$ 5,395
Debt – Midstream (Hess Midstream Operations LP):		
Senior unsecured fixed-rate public notes:		
5.625% due 2026	**$ 795**	$ 793
5.125% due 2028	**545**	544
4.250% due 2030	**742**	740
5.500% due 2030	**395**	395
Total senior unsecured fixed-rate public notes	**2,477**	2,472
Term Loan A facility	**394**	396
Revolving credit facility	**340**	18
Total Debt – Midstream	**$ 3,211**	$ 2,886
Total Debt:		
Current portion of long-term debt	**$ 311**	$ 3
Long-term debt	**8,302**	8,278
Total Debt	**$ 8,613**	$ 8,281

At December 31, 2023, the maturity profile of total debt was as follows:

	Total	Hess Corporation	Midstream
		(In millions)	
2024	$ 311	$ 298	$ 13
2025	22	—	22
2026	832	—	832
2027	1,670	1,000	670
2028	550	—	550
Thereafter	5,290	4,140	1,150
Total Borrowings	8,675	5,438	3,237
Less: Deferred financing costs and discounts	(62)	(36)	(26)
Total Debt (excluding interest)	$ 8,613	$ 5,402	$ 3,211

In 2023, $48 million of interest was capitalized (2022: $10 million; 2021: $0 million).

Debt – Hess Corporation:

Senior unsecured fixed-rate public notes:

At December 31, 2023, Hess Corporation's fixed-rate senior unsecured notes had a gross principal amount of $5,438 million (2022: $5,438 million) and a weighted average interest rate of 5.9% (2022: 5.9%). The indentures for our fixed-rate senior unsecured notes limit the ratio of secured debt to Consolidated Net Tangible Assets (as that term is defined in the indentures) to 15%. As of December 31, 2023, Hess Corporation was in compliance with this financial covenant.

Credit facility:

The revolving credit facility can be used for borrowings and letters of credit. Borrowings on the facility will generally bear interest at 1.400% above SOFR, though the interest rate is subject to adjustment based on the credit rating of the Corporation's senior, unsecured, non-credit enhanced long-term debt. The revolving credit facility is subject to customary representations, warranties, customary events of default and covenants, including a financial covenant limiting the ratio of Total Consolidated Debt to Total Capitalization of the Corporation and its consolidated subsidiaries to 65%, and a financial covenant limiting the ratio of secured debt to Consolidated Net Tangible Assets of the Corporation and its consolidated subsidiaries to 15% (as these capitalized terms are defined in the credit agreement for the revolving credit facility). As of December 31, 2023, Hess Corporation was in compliance with these financial covenants. At December 31, 2023, Hess Corporation had no outstanding borrowings or letters of credit under its revolving credit facility.

Other outstanding letters of credit at December 31 were as follows:

	2023	2022
	(In millions)	
Committed lines (a)	**$ 2**	$ —
Uncommitted lines (a)	**86**	83
Total	**$ 88**	$ 83

(a) At December 31, 2023, committed and uncommitted lines have expiration dates through 2024.

The most restrictive of the financial covenants relating to our fixed-rate senior unsecured notes and our revolving credit facility would allow us to borrow up to an additional $2,515 million of secured debt at December 31, 2023.

Debt – Midstream (Hess Midstream Operations LP):

Senior unsecured fixed-rate public notes:

At December 31, 2023, HESM Opco's fixed-rate senior unsecured notes had a gross principal amount of $2,500 million (2022: $2,500 million) and a weighted average interest rate of 5.1% (2022: 5.1%). HESM Opco's senior unsecured notes are guaranteed by certain of HESM Opco's direct and indirect wholly owned material domestic subsidiaries. These senior unsecured notes are non-recourse to Hess Corporation.

In April 2022, HESM Opco issued $400 million in aggregate principal amount of 5.500% fixed-rate senior unsecured notes due in 2030 in a private offering to repay borrowings under its revolving credit facility used to finance the repurchase of approximately 13.6 million HESM Opco Class B units held by Hess and GIP. In August 2021, HESM Opco issued $750 million in aggregate principal amount of 4.250% fixed-rate senior unsecured notes due in 2030 in a private offering to finance the repurchase of 31.25 million HESM Opco Class B units held by Hess and GIP.

Credit facilities:

At December 31, 2023, HESM Opco had $1.4 billion of senior secured syndicated credit facilities, consisting of a $1.0 billion revolving credit facility and a $400 million term loan facility. Borrowings under the term loan facility will generally bear interest at SOFR plus an applicable margin ranging from 1.650% to 2.550%, while the applicable margin for the syndicated revolving credit facility ranges from 1.375% to 2.050%. Pricing levels for the facility fee and interest-rate margins are based on HESM Opco's ratio of total debt to EBITDA (as defined in the credit facilities). If HESM Opco obtains an investment grade credit rating, the pricing levels will be based on HESM Opco's credit ratings in effect from time to time. The credit facilities contain covenants that require HESM Opco to maintain a ratio of total debt to EBITDA (as defined in the credit facilities) for the prior four fiscal quarters of not greater than 5.00 to 1.00 as of the last day of each fiscal quarter (5.50 to 1.00 during the specified period following certain acquisitions) and, prior to HESM Opco obtaining an investment grade credit rating, a ratio of secured debt to EBITDA for the prior four fiscal quarters of not greater than 4.00 to 1.00 as of the last day of each fiscal quarter. HESM Opco was in compliance with these financial covenants at December 31, 2023. The credit facilities are secured by first-priority perfected liens on substantially all of the assets of HESM Opco and its direct and indirect wholly owned material domestic subsidiaries, including equity interests directly owned by such entities, subject to certain customary exclusions. At December 31, 2023, borrowings of $340 million were drawn under HESM Opco's revolving credit facility, and borrowings of $397 million, excluding deferred issuance costs, were drawn under HESM Opco's term loan facility. Borrowings under these credit facilities are non-recourse to Hess Corporation.

8. Asset Retirement Obligations

The following table describes the changes in our asset retirement obligations for the years ended December 31:

	2023	2022
	(In millions)	
Balance at January 1	**$ 1,241**	$ 1,190
Liabilities incurred	**135**	126
Liabilities settled or disposed of (a)	**(240)**	(213)
Accretion expense	**61**	48
Revisions of estimated liabilities	**148**	92
Foreign currency remeasurement	**1**	(2)
Balance at December 31	**$ 1,346**	$ 1,241
Total Asset Retirement Obligations at December 31:		
Current portion of asset retirement obligations	**$ 160**	$ 207
Long-term asset retirement obligations	**1,186**	1,034
Total at December 31	**$ 1,346**	$ 1,241

(a) Payments to settle asset retirement obligations are presented in Changes in other operating assets and liabilities on the Statement of Consolidated Cash Flows.

The liabilities incurred in 2023 primarily relate to operations in Guyana while liabilities incurred in 2022 primarily relate to operations in Guyana and Malaysia. Liabilities settled or disposed of in 2023 and 2022 primarily result from abandonment activity completed in the Gulf of Mexico and the Bakken.

Revisions of estimated liabilities in 2023 include $82 million that resulted from revisions to estimated costs to abandon certain wells, pipelines and production facilities in the West Delta Field in the Gulf of Mexico. See *Note 12, Impairment and Other*. Other revisions of estimated liabilities in 2023 primarily reflect changes in service and equipment rates. Revisions of estimated liabilities in 2022 primarily reflect changes in service and equipment rates.

Sinking fund deposits that are legally restricted for purposes of settling asset retirement obligations, which are reported in non-current *Other assets* in the *Consolidated Balance Sheet*, were $294 million at December 31, 2023 (2022: $261 million).

9. Retirement Plans

We have funded noncontributory defined benefit pension plans for a significant portion of our employees. In addition, we have an unfunded supplemental pension plan covering certain employees, which provides incremental payments that would have been payable from our principal pension plans, were it not for limitations imposed by income tax regulations. The plans provide defined benefits based on years of service and final average salary to our U.S. employees hired prior to January 1, 2017 and to our employees in the United Kingdom (U.K.). The U.S. employees hired on or after January 1, 2017 participate under a cash accumulation formula and receive credits to a notional account based on a percentage of pensionable wages. Interest accrues on the balance in the notional account at a rate determined in accordance with plan provisions. Additionally, we maintain an unfunded post-retirement medical plan that provides health benefits to certain U.S. qualified retirees from ages 55 through 65. The measurement date for all retirement plans is December 31.

The following table summarizes the benefit obligations, the fair value of plan assets, and the funded status of our pension and postretirement medical plans:

	Funded Pension Plans		Unfunded Pension Plan		Postretirement Medical Plan	
	2023	**2022**	**2023**	**2022**	**2023**	**2022**
	(In millions)					
Change in Benefit Obligation						
Balance at January 1,	**$ 1,802**	$ 2,948	**$ 212**	$ 248	**$ 52**	$ 59
Service cost	**26**	33	**9**	11	**3**	3
Interest cost	**88**	66	**9**	3	**2**	1
Actuarial (gain) loss (a)	**44**	(818)	**7**	(38)	**1**	(7)
Plan settlements	**(143)**	(266)	**—**	—	**—**	—
Benefit payments	**(77)**	(90)	**(15)**	(12)	**(5)**	(4)
Foreign currency exchange rate changes	**20**	(71)	**—**	—	**—**	—
Balance at December 31, (b)	**$ 1,760**	$ 1,802	**$ 222**	$ 212	**$ 53**	$ 52
Change in Fair Value of Plan Assets						
Balance at January 1,	**$ 2,450**	$ 3,357	**$ —**	$ —	**$ —**	$ —
Actual return on plan assets	**186**	(469)	**—**	—	**—**	—
Employer contributions	**1**	1	**15**	12	**5**	4
Plan settlements	**(143)**	(266)	**—**	—	**—**	—
Benefit payments	**(77)**	(90)	**(15)**	(12)	**(5)**	(4)
Foreign currency exchange rate changes	**28**	(83)	**—**	—	**—**	—
Balance at December 31,	**$ 2,445**	$ 2,450	**$ —**	$ —	**$ —**	$ —
Funded Status (Plan assets greater (less) than benefit obligations) at December 31,	**$ 685**	$ 648	**$ (222)**	$ (212)	**$ (53)**	$ (52)
Unrecognized Net Actuarial (Gains) Losses (c)	**$ 332**	$ 337	**$ 30**	$ 23	**$ (25)**	$ (27)

(a) In 2023, changes in discount rates resulted in actuarial losses of $56 million, updates to census data resulted in actuarial losses of $18 million, and the alignment of the projected benefit obligation to the amount of plan settlement payments resulted in actuarial gains of $20 million. Changes in all other assumptions resulted in net actuarial gains of $2 million in 2023. In 2022, changes in discount rates resulted in actuarial gains of $874 million and changes in mortality assumptions resulted in actuarial losses of $8 million. Changes in all other assumptions, including inflation and demographic assumptions, resulted in net actuarial losses of $3 million in 2022.

(b) At December 31, 2023, the accumulated benefit obligation for the funded and unfunded defined benefit pension plans was $1,684 million and $181 million, respectively (2022: $1,743 million and $180 million, respectively).

(c) At December 31, 2023, the unrecognized net actuarial losses related to the U.K. pension plan was $179 million (2022: $175 million).

Amounts recognized in the *Consolidated Balance Sheet* at December 31 consisted of the following:

	Funded Pension Plans		Unfunded Pension Plan		Postretirement Medical Plan	
	2023	**2022**	**2023**	**2022**	**2023**	**2022**
			(In millions)			
Noncurrent assets	**$ 685**	$ 648	**$ —**	$ —	**$ —**	$ —
Current liabilities	**—**	—	**(23)**	(24)	**(5)**	(6)
Noncurrent liabilities	**—**	—	**(199)**	(188)	**(48)**	(46)
Post-retirement benefit assets / (liabilities)	**$ 685**	$ 648	**$ (222)**	$ (212)	**$ (53)**	$ (52)
Accumulated other comprehensive (income) loss, pre-tax (a)	**$ 332**	$ 337	**$ 30**	$ 23	**$ (25)**	$ (27)

(a) The after-tax deficit reflected in Accumulated other comprehensive income (loss) was $134 million at December 31, 2023 (2022: $131 million deficit).

The net periodic benefit cost for funded and unfunded pension plans, and the postretirement medical plan, is as follows:

	Pension Plans			Postretirement Medical Plan		
	2023	**2022**	**2021**	**2023**	**2022**	**2021**
			(In millions)			
Service cost	**$ 35**	$ 44	$ 51	**$ 3**	$ 3	$ 3
Interest cost	**97**	69	55	**2**	1	1
Expected return on plan assets	**(156)**	(196)	(197)	**—**	—	—
Amortization of unrecognized net actuarial losses (gains)	**3**	11	58	**(2)**	(1)	(1)
Settlement loss	**17**	2	9	**—**	—	—
Net Periodic Benefit Cost / (Income) (a)	**$ (4)**	**$ (70)**	**$ (24)**	**$ 3**	**$ 3**	**$ 3**

(a) Net non-service cost, which is included in Other, net in the Statement of Consolidated Income, was income of $39 million in 2023 (2022: $114 million of income; 2021: $75 million of income).

In 2023, the Hess Corporation Employees' Pension Plan paid lump sums to certain participants totaling $143 million which resulted in a noncash settlement loss of $17 million to recognize unamortized actuarial losses.

In 2022, the Hess Corporation Employees' Pension Plan purchased a single premium annuity contract at a cost of $166 million using assets of the plan to settle and transfer certain of its obligations to a third party. This partial settlement resulted in a noncash settlement loss of $13 million to recognize unamortized actuarial losses.

In 2022, the HOVENSA Legacy Employees' Pension Plan paid lump sums to certain participants totaling $20 million, and purchased a single premium annuity contract at a cost of $80 million, to settle the plan's projected benefit obligation in connection with terminating the plan. The settlement transactions resulted in a noncash settlement gain of $11 million to recognize unamortized actuarial gains. The assets remaining after settlement of the plan's projected benefit obligation of $15 million were transferred to the Hess Corporation Employees' Pension Plan in December 2022.

In 2024, we forecast service cost for our pension and post-retirement medical plans to be approximately $40 million and net non-service cost of approximately $65 million of income, which is comprised of interest cost of approximately $90 million, and estimated expected return on plan assets of approximately $155 million.

The board of trustees for our U.K. pension plan is evaluating various alternatives to settle all or a portion of the plan's projected benefit obligation. A decision to proceed will occur only after the board of trustees receives and evaluates proposals and determines that the transaction is in the best interest of plan participants. Should a settlement be completed, a material noncash settlement loss may be recorded reflecting any difference between the settlement value and projected benefit obligation, and the acceleration of the recognition of unrecognized actuarial losses.

Assumptions: The weighted average actuarial assumptions used to determine benefit obligations at December 31 and net periodic benefit cost for the three years ended December 31 for our funded and unfunded pension plans were as follows:

	2023	2022	2021
Benefit Obligations:			
Discount rate	**4.8%**	5.0%	2.5%
Rate of compensation increase	**3.9%**	4.0%	3.8%
Net Periodic Benefit Cost:			
Discount rate			
Service cost	**5.0%**	3.3%	2.6%
Interest cost	**4.9%**	3.0%	1.7%
Expected rate of return on plan assets	**6.5%**	6.5%	6.6%
Rate of compensation increase	**4.0%**	3.8%	3.8%

The actuarial assumptions used to determine benefit obligations at December 31 for the post-retirement medical plan were as follows:

	2023	2022	2021
Discount rate	**4.7%**	4.9%	2.4%
Initial health care trend rate	**6.0%**	6.3%	5.5%
Ultimate trend rate	**4.0%**	4.0%	4.0%
Year in which ultimate trend rate is reached	**2046**	2046	2046

The assumptions used to determine net periodic benefit cost for each year were established at the end of each previous year. In 2022 and 2021, there was an interim remeasurement of the funded status of certain plans due to plan settlements which resulted in net periodic benefit cost being recalculated for the remainder of the year using assumptions as of the interim remeasurement dates. The assumptions disclosed in the preceding table used to determine net periodic benefit cost for 2022 and 2021 are a weighted average of the assumptions as of the end of the previous year and the interim remeasurement dates. Due to the timing of plan settlements in 2023, an interim remeasurement of the funded status was unnecessary in 2023. The assumptions used to determine benefit obligations were established at each year end. Discount rates are developed based on a portfolio of high-quality, fixed income debt instruments with maturities that approximate the expected payment of plan obligations.

The overall expected rate of return on plan assets is developed from the expected future returns for each asset category, weighted by the target allocation of assets to that asset category. The future expected rate of return assumptions for individual asset categories are largely based on inputs from various investment experts regarding their future return expectations for particular asset categories. The expected rate of return on plan assets is applied to the fair value of plan assets to determine the expected return on plan assets component of net periodic benefit cost for the year.

Our investment strategy is to maximize long-term returns at an acceptable level of risk through broad diversification of plan assets in a variety of asset classes. Asset classes and target allocations are determined by our investment committee and include domestic and foreign equities, fixed income, and other investments, including hedge funds, real estate and private equity. Investment managers are prohibited from investing in securities issued by us unless indirectly held as part of an index strategy. The majority of plan assets are highly liquid, providing ample liquidity for benefit payment requirements. The current target allocations are 30% equity securities, 50% fixed income securities (including cash and short-term investment funds) and 20% to all other types of investments. Asset allocations are rebalanced on a periodic basis throughout the year to bring assets to within an acceptable range of target levels.

Fair value: The following tables provide the fair value of the financial assets of the funded pension plans at December 31, 2023 and 2022 in accordance with the fair value measurement hierarchy described in *Note 1, Nature of Operations, Basis of Presentation and Summary of Accounting Policies*.

	Level 1	Level 2	Level 3	Net Asset Value (c)	Total
			(In millions)		
December 31, 2023					
Cash and Short-Term Investment Funds	**$ 27**	**$ —**	**$ —**	**$ —**	**$ 27**
Equities:					
U.S. equities (domestic)	**309**	**—**	**—**	**—**	**309**
International equities (non-U.S.)	**52**	**—**	**—**	**158**	**210**
Global equities (domestic and non-U.S.)	**—**	**6**	**—**	**55**	**61**
Fixed Income:					
Treasury and government related (a)	**—**	**581**	**—**	**—**	**581**
Mortgage-backed securities (b)	**—**	**98**	**—**	**12**	**110**
Corporate	**—**	**547**	**—**	**3**	**550**
Other:					
Hedge funds	**—**	**—**	**—**	**—**	**—**
Private equity funds	**—**	**—**	**—**	**414**	**414**
Real estate funds	**—**	**—**	**—**	**183**	**183**
Total investments	**$ 388**	**$ 1,232**	**$ —**	**$ 825**	**$ 2,445**
December 31, 2022					
Cash and Short-Term Investment Funds	$ 51	$ —	$ —	$ —	$ 51
Equities:					
U.S. equities (domestic)	409	—	—	11	420
International equities (non-U.S.)	62	11	—	306	379
Global equities (domestic and non-U.S.)	—	5	—	90	95
Fixed Income:					
Treasury and government related (a)	—	364	—	—	364
Mortgage-backed securities (b)	—	142	—	18	160
Corporate	—	304	—	8	312
Other:					
Hedge funds	—	—	—	75	75
Private equity funds	—	—	—	374	374
Real estate funds	9	—	—	211	220
Total investments	$ 531	$ 826	$ —	$ 1,093	$ 2,450

(a) Includes securities issued and guaranteed by U.S. and non-U.S. governments, and securities issued by governmental agencies and municipalities.
(b) Comprised of U.S. residential and commercial mortgage-backed securities.
(c) Includes certain investments that have been valued using the net asset value (NAV) practical expedient, and therefore have not been categorized in the fair value hierarchy. The inclusion of such amounts in the above table is intended to aid reconciliation of investments categorized in the fair value hierarchy to total pension plan assets.

The following describes the financial assets of the funded pension plans:

Cash and short-term investment funds – Consists of cash on hand and short-term investment funds that provide for daily investments and redemptions which are classified as Level 1.

Equities – Consists of individually held U.S. and international equity securities. This investment category also includes funds that consist primarily of U.S. and international equity securities. Equity securities, which are individually held and are traded actively on exchanges, are classified as Level 1. Certain funds, consisting primarily of equity securities, are classified as Level 2 if the NAV is determined and published daily, and is the basis for current transactions. Commingled funds, consisting primarily of equity securities held in unitized trusts, are valued using the NAV per fund share.

Fixed income investments – Consists of individually held securities issued by the U.S. government, non-U.S. governments, governmental agencies, municipalities and corporations, and agency and non-agency mortgage-backed securities. This investment category also includes funds that consist primarily of fixed income securities. Individual fixed income securities are generally valued on the basis of evaluated prices from independent pricing services. Such prices are monitored by the trustee, which also serves as the independent third-party custodial firm responsible for safekeeping assets of the particular plan, and are classified as Level 2. Exchange-traded funds consisting of fixed income securities are classified as Level 1. Certain funds, consisting primarily of fixed income securities, are classified as Level 2 if the NAV is determined and published daily, and is the basis for current transactions. Commingled funds, consisting primarily of fixed income securities, are valued using the NAV per fund share.

Other investments – Consists of exchange-traded real estate investment trust securities, which are classified as Level 1. Commingled funds and limited partnership investments in hedge funds, private equity and real estate funds are valued at the NAV per fund share.

Contributions and estimated future benefit payments: In 2024, we expect to contribute approximately $25 million to our funded pension plans.

Estimated future benefit payments by the funded and unfunded pension plans, and the post-retirement medical plan, which reflect expected future service, are as follows (in millions):

2024	$	112
2025		117
2026		167
2027		117
2028		123
Years 2029 to 2033		611

We also have defined contribution plans for certain eligible employees. Employees may contribute a portion of their compensation to these plans and we match a portion of the employee contributions. We recorded expense of $24 million in 2023 for contributions to these plans (2022: $22 million; 2021: $18 million).

10. Revenue

Revenue from contracts with customers on a disaggregated basis was as follows (in millions):

	Exploration and Production					Midstream	Eliminations	Total
	United States	Guyana	Malaysia and JDA	Other (a)	E&P Total			
2023								
Sales of net production volumes:								
Crude oil revenue	$ 3,058	$ 3,486	$ 144	$ —	$ 6,688	$ —	$ —	$ 6,688
Natural gas liquids revenue	529	—	—	—	529	—	—	529
Natural gas revenue	182	—	800	—	982	—	—	982
Sales of purchased oil and gas	2,390	70	—	—	2,460	—	—	2,460
Third-party services	—	—	—	—	—	8	—	8
Intercompany revenue	—	—	—	—	—	1,338	(1,338)	—
Total sales (b)	6,159	3,556	944	—	10,659	1,346	(1,338)	10,667
Other operating revenues (c)	(78)	(62)	(19)	—	(159)	3	—	(156)
Total sales and other operating revenues	$ 6,081	$ 3,494	$ 925	$ —	$ 10,500	$ 1,349	$ (1,338)	$ 10,511
2022								
Sales of net production volumes:								
Crude oil revenue	$ 3,407	$ 2,771	$ 134	$ 509	$ 6,821	$ —	$ —	$ 6,821
Natural gas liquids revenue	703	—	—	—	703	—	—	703
Natural gas revenue	438	—	739	21	1,198	—	—	1,198
Sales of purchased oil and gas	2,978	53	—	112	3,143	—	—	3,143
Intercompany revenue	—	—	—	—	—	1,273	(1,273)	—
Total sales (b)	7,526	2,824	873	642	11,865	1,273	(1,273)	11,865
Other operating revenues (c)	(312)	(188)	—	(41)	(541)	—	—	(541)
Total sales and other operating revenues	$ 7,214	$ 2,636	$ 873	$ 601	$ 11,324	$ 1,273	$ (1,273)	$ 11,324
2021								
Sales of net production volumes:								
Crude oil revenue	$ 2,958	$ 765	$ 83	$ 519	$ 4,325	$ —	$ —	$ 4,325
Natural gas liquids revenue	594	—	—	—	594	—	—	594
Natural gas revenue	350	—	655	10	1,015	—	—	1,015
Sales of purchased oil and gas	1,638	16	—	95	1,749	—	—	1,749
Intercompany revenue	—	—	—	—	—	1,204	(1,204)	—
Total sales (b)	5,540	781	738	624	7,683	1,204	(1,204)	7,683
Other operating revenues (c)	(162)	(27)	—	(21)	(210)	—	—	(210)
Total sales and other operating revenues	$ 5,378	$ 754	$ 738	$ 603	$ 7,473	$ 1,204	$ (1,204)	$ 7,473

(a) Other includes our interest in the Waha Concession in Libya, which was sold in November 2022, and our interests in Denmark, which were sold in August 2021.

(b) Guyana crude oil revenue includes $433 million of revenue from non-customers in 2023 (2022: $230 million). There was no sales revenue from non-customers in 2021.

(c) Other operating revenues are not a component of revenues from contracts with customers. Included within other operating revenues are gains (losses) on commodity derivatives of $(190) million in 2023, $(585) million in 2022, and $(243) million in 2021.

11. Dispositions

2022: We completed the sale of our 8% interest in the Waha Concession in Libya for net cash consideration of $150 million and recognized a pre-tax gain of $76 million ($76 million after income taxes). We also completed the sale of real property related to our former downstream business for cash consideration of $24 million and recognized a pre-tax gain of $22 million ($22 million after income taxes).

2021: We completed the sale of our interests in Denmark for net cash consideration of approximately $130 million, after normal closing adjustments, and recognized a pre-tax gain of $29 million ($29 million after income taxes). In addition, we completed the sale of our Little Knife and Murphy Creek nonstrategic acreage interests in the Bakken for net cash consideration of $297 million, after normal closing adjustments. The sale included approximately 78,700 net acres, which are located in the southernmost portion of the Corporation's Bakken position. The acreage constituted part of a larger amortization base and the sale was treated as a normal retirement. Accordingly, no gain or loss was recognized upon sale.

12. Impairment and Other

2023: We recorded a pre-tax charge of $82 million ($82 million after income taxes) that resulted from revisions to estimated costs to abandon certain wells, pipelines and production facilities in the West Delta Field in the Gulf of Mexico. These abandonment obligations were assigned to us as a former owner after they were discharged from Fieldwood Energy LLC (Fieldwood) as part of its approved bankruptcy plan in 2021. See *Note 8, Asset Retirement Obligations*.

2022: We recorded a pre-tax charge of $28 million ($28 million after income taxes) that resulted from updates to our estimated abandonment liabilities for non-producing properties in the Gulf of Mexico and $26 million ($26 million after income taxes) to fully impair the net book value of our interests in the Penn State Field in the Gulf of Mexico due to a mechanical issue on the field's remaining production well.

2021: In June 2021, the U.S. Bankruptcy Court approved the bankruptcy plan of Fieldwood, which included the abandonment of certain assets, including seven offshore Gulf of Mexico leases and related facilities in the West Delta Field that were formerly owned by us and sold to a Fieldwood predecessor in 2004, and the discharge of Fieldwood's obligation to decommission these facilities. As a result, we recognized a pre-tax charge of $147 million ($147 million after income taxes) in connection with the estimated abandonment obligations in the West Delta Field.

13. Share-based Compensation

We have established and maintain LTIP for the granting of restricted common shares, PSUs and stock options to our employees. At December 31, 2023, the total number of authorized common stock under the LTIP was 63.5 million shares, of which we have 19.9 million shares available for issuance. Share-based compensation expense consisted of the following:

	2023	2022	2021
		(In millions)	
Restricted stock	**$ 55**	$ 52	$ 49
Performance share units	**21**	20	18
Stock options	**11**	11	10
Share-based compensation expense before income taxes	**$ 87**	$ 83	$ 77
Income tax benefit on share-based compensation expense	**$ —**	$ —	$ —

Based on share-based compensation awards outstanding at December 31, 2023, unearned compensation expense, before income taxes, of $89 million is expected to be recognized over a weighted average period of 1.8 years.

Our share-based compensation plans can be summarized as follows:

Restricted stock:

Restricted stock generally vests equally on an annual basis over a three-year term and is valued based on the prevailing market price of our common stock on the date of grant. The following is a summary of restricted stock award activity in 2023:

	Shares of Restricted Common Stock	Weighted - Average Price on Date of Grant
	(In thousands, except per share amounts)	
Outstanding at January 1, 2023	1,312	$ 80.61
Granted	470	141.76
Vested (a)	(735)	73.24
Forfeited	(26)	104.14
Outstanding at December 31, 2023	1,021	$ 113.47

(a) In 2023, restricted stock with a vesting date fair value of $104 million were vested (2022: $86 million; 2021: $72 million).

Performance share units:

PSUs generally vest three years from the date of grant and are valued using a Monte Carlo simulation on the date of grant.

For the PSU's granted in 2021 and 2022, the number of shares of common stock to be issued under a PSU agreement is based on a comparison of the Corporation's total shareholder return (TSR) to the TSR of a predetermined group of peer companies and the S&P 500 index over a three-year performance period ending December 31 of the year prior to settlement of the grant. Payouts of the performance share awards will range from 0% to 200% of the target awards based on the Corporation's TSR ranking within the peer group. Dividend equivalents for the performance period will accrue on performance shares but will only be paid out on earned shares after the performance period.

For the PSU's granted in 2023, the number of shares of common stock to be issued under a PSU agreement is based on a comparison of the Corporation's total shareholder return compound annual growth rate (TSR CAGR) to the TSR CAGR of the SPDR S&P Oil & Gas Exploration and Production ETF (XOP), with a modifier determined by comparing the Corporation's TSR CAGR to the TSR CAGR of the S&P 500 index, over a three-year performance period ending December 31, 2025. Payout of the performance share awards will range from 0% to 200% of the target awards based on the comparison of the Corporation's TSR CAGR to the XOP's TSR CAGR. The modifier can only adjust the payout percentage by plus or minus 10%, up to a maximum of 210% or a minimum of 0%. Dividend equivalents for the performance period will accrue on performance shares but will only be paid out on earned shares after the performance period.

The following is a summary of PSU activity in 2023:

	Performance Share Units		Weighted - Average Fair Value on Date of Grant
	(In thousands, except per share amounts)		
Outstanding at January 1, 2023	686	$	81.25
Granted	130		178.80
Vested (a)	(303)		57.93
Forfeited	(1)		104.54
Outstanding at December 31, 2023	512	$	119.77

(a) In 2023, PSU's with a vesting date fair value of $55 million were vested (2022: $37 million; 2021: $30 million).

The following weighted average assumptions were utilized to estimate the fair value of PSU awards:

		2023		2022		2021
Risk free interest rate		**4.61 %**		1.59 %		0.29 %
Stock price volatility		**0.478**		0.584		0.579
Contractual term in years		**3.0**		3.0		3.0
Grant date price of Hess common stock	**$**	**141.95**	$	101.17	$	75.04

Stock options:

Stock options vest over three years from the date of grant, have a 10-year term, and the exercise price equals the market price of our common stock on the date of grant. The following is a summary of stock options activity in 2023:

	Number of options (In thousands)		Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term
Outstanding at January 1, 2023	1,481	$	69.31	6.6 years
Granted	189		141.71	
Exercised	(157)		64.34	
Forfeited	(3)		90.73	
Outstanding at December 31, 2023	1,510	$	78.85	6.1 years

At December 31, 2023, there were 1.5 million outstanding stock options (1.0 million exercisable) with a weighted average exercise price of $78.85 per share ($64.07 per share for exercisable options), a weighted average remaining contractual life of 6.1 years (5.1 years for exercisable options) and an aggregate intrinsic value of $105 million ($88 million for exercisable options). The intrinsic value of stock options exercised in 2023 was $13 million (2022: $44 million, 2021: $45 million).

The following weighted average assumptions were utilized to estimate the fair value of stock options:

		2023		2022		2021
Risk free interest rate		**4.20 %**		1.66 %		0.95 %
Stock price volatility		**0.469**		0.457		0.470
Dividend yield		**1.24 %**		1.48 %		1.33 %
Expected life in years		**6.0**		6.0		6.0
Weighted average fair value per option granted	**$**	**63.45**	$	39.51	$	29.66

In estimating the fair value of PSUs and stock options, the risk-free interest rate is based on the expected term of the award and is obtained from published sources. The stock price volatility is determined from the historical stock prices of the Corporation using the expected term.

14. Income Taxes

The provision (benefit) for income taxes consisted of:

	2023	2022	2021
		(In millions)	
United States			
Federal			
Current	**$ —**	$ —	$ —
Deferred taxes and other accruals	**31**	22	12
State	**7**	5	3
	38	27	15
Foreign			
Current (a)	**537**	789	478
Deferred taxes and other accruals	**158**	283	107
	695	1,072	585
Provision (Benefit) For Income Taxes	**$ 733**	$ 1,099	$ 600

(a) Primarily comprised of Guyana in 2023, Guyana and Libya in 2022, and Libya in 2021.

Income (loss) before income taxes consisted of the following:

	2023	2022	2021
		(In millions)	
United States (a)	**$ (191)**	$ 569	$ 143
Foreign	**2,662**	2,977	1,347
Income (Loss) Before Income Taxes	**$ 2,471**	$ 3,546	$ 1,490

(a) Includes substantially all of our interest expense, corporate expense, the results of commodity hedging activities, and amounts attributable to noncontrolling interests.

The difference between our effective income tax rate and the U.S. statutory rate is reconciled below:

	2023	2022	2021
U.S. statutory rate	**21.0 %**	21.0 %	21.0 %
Effect of foreign operations (a)	**7.5**	16.5	28.0
State income taxes, net of federal income tax	**0.2**	0.1	0.2
Valuation allowance on current year operations	**4.5**	(4.8)	(5.3)
Release of valuation allowance	**(1.3)**	—	—
Noncontrolling interests in Midstream	**(2.0)**	(1.6)	(4.0)
Equity and executive compensation	**(0.2)**	(0.2)	0.4
Total	**29.7 %**	31.0 %	40.3 %

(a) The variance in effective income tax rates attributable to the effect of foreign operations is primarily driven by Guyana in 2023 and Libya in 2022 and 2021.

The components of deferred tax liabilities and deferred tax assets at December 31, were as follows:

	2023	2022
	(In millions)	
Deferred Tax Liabilities		
Property, plant and equipment and investments	**$ (2,117)**	$ (1,742)
Other	**(108)**	(99)
Total Deferred Tax Liabilities	**(2,225)**	(1,841)
Deferred Tax Assets		
Net operating loss carryforwards	**4,406**	4,226
Tax credit carryforwards	**109**	98
Property, plant and equipment and investments	**413**	233
Accrued compensation, deferred credits and other liabilities	**109**	85
Asset retirement obligations	**296**	279
Other	**256**	293
Total Deferred Tax Assets	**5,589**	5,214
Valuation allowances (a)	**(3,652)**	(3,658)
Total deferred tax assets, net of valuation allowances	**1,937**	1,556
Net Deferred Tax Assets (Liabilities)	**$ (288)**	$ (285)

(a) In 2023, the valuation allowance decreased by $6 million (2022: decrease of $180 million; 2021: decrease of $1,553 million).

In the *Consolidated Balance Sheet*, deferred tax assets and liabilities are netted by taxing jurisdiction and are recorded at December 31, as follows:

	2023	2022
	(In millions)	
Deferred income taxes (long-term asset)	**$ 320**	$ 133
Deferred income taxes (long-term liability)	**(608)**	(418)
Net Deferred Tax Assets (Liabilities)	**$ (288)**	$ (285)

At December 31, 2023, we have a gross deferred tax asset related to net operating loss carryforwards of $4,406 million before application of valuation allowances. The deferred tax asset is comprised of $127 million attributable to foreign net operating losses which will begin to expire in 2025, $3,778 million attributable to U.S. federal operating losses which will begin to expire in 2034, and $501 million attributable to losses in various U.S. states which will begin to expire in 2024. The deferred tax asset attributable to foreign net operating losses, net of valuation allowances, is $23 million. A full valuation allowance is established against the deferred tax asset attributable to U.S. federal and state net operating losses, except for $38 million of U.S. federal and $8 million of U.S. state deferred tax assets attributable to Midstream activities for which separate U.S. federal and state tax returns are filed. At December 31, 2023, we have U.S. state tax credit carryforwards of $27 million, which will begin to expire in 2034, $81 million of other business credit carryforwards, which will begin to expire in 2036, and foreign tax credit carryforwards of $1 million, which will begin to expire in 2024. A full valuation allowance is established against the deferred tax asset attributable to these credits.

At December 31, 2023, the *Consolidated Balance Sheet* reflects a $3,652 million (2022: $3,658 million) valuation allowance against the net deferred tax assets for multiple jurisdictions based on application of the relevant accounting standards. Hess continues to maintain a full valuation allowance against its deferred tax assets in the U.S. (non-Midstream) and certain other jurisdictions. The reduction in valuation allowance year over year is primarily due to a partial release of the valuation allowance in Malaysia, partially offset with an increase in deferred tax asset balances in other jurisdictions. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. In December 2023, the valuation allowance established against a portion of the net deferred tax assets in Malaysia, related to the Marginal Field tax ring-fence was released in the amount of $33 million as a result of the emergence from a cumulative loss position and positive evidence from forecasted pre-tax income from operations. The remaining valuation allowance in Malaysia is associated with net deferred tax assets of other tax ring-fences which lack sufficient positive evidence to support realizability. While we emerged from a recent cumulative loss position in the U.S. (non-Midstream) in 2023, the cumulative income position is near breakeven. Until we see a more significant and sustained pattern of objectively verifiable income, we do not assign significant weight to subjective long-term projections of future income and thus maintain a full valuation allowance against our U.S. (non-Midstream) federal and state deferred tax assets. If anticipated future earnings are exceeded, sufficient positive evidence may become available to support the release of valuation allowance in the future. This would result in the recognition of certain deferred tax assets on the balance sheet and a decrease to income tax expense for the period in which the release is recognized.

Below is a reconciliation of the gross beginning and ending amounts of unrecognized tax benefits:

	2023	2022	2021
		(In millions)	
Balance at January 1	**$ 120**	$ 133	$ 166
Additions based on tax positions taken in the current year	**—**	17	12
Additions based on tax positions of prior years	**—**	—	3
Reductions based on tax positions of prior years	**(9)**	(30)	(48)
Balance at December 31	**$ 111**	$ 120	$ 133

There is no balance at December 31, 2023 for unrecognized tax benefits that, if recognized would impact our effective income tax rate. Over the next 12 months, we have no unrecognized benefit that is reasonably possible to decrease due to settlements with taxing authorities or other resolutions, as well as lapses in statutes of limitation. At December 31, 2023, we have no accrued interest and penalties related to unrecognized tax benefits (2022: $0 million).

We file income tax returns in the U.S. and various foreign jurisdictions. We are no longer subject to examinations by income tax authorities in most jurisdictions for years prior to 2009.

15. Outstanding and Weighted Average Common Shares

Net income and weighted average number of common shares used in the basic and diluted earnings per share computations were as follows:

	2023	2022	2021
	(In millions except per share amounts)		
Net Income Attributable to Hess Corporation:			
Net income	**$ 1,738**	$ 2,447	$ 890
Less: Net income attributable to noncontrolling interests	**356**	351	331
Net income attributable to Hess Corporation	**$ 1,382**	$ 2,096	$ 559
Weighted Average Number of Common Shares Outstanding:			
Basic	**305.9**	308.1	307.4
Effect of dilutive securities			
Restricted common stock	**0.5**	0.7	0.7
Stock options	**0.7**	0.6	0.4
Performance share units	**0.5**	0.2	0.8
Diluted	**307.6**	309.6	309.3
Net Income Attributable to Hess Corporation per Common Share:			
Basic	**$ 4.52**	$ 6.80	$ 1.82
Diluted	**$ 4.49**	$ 6.77	$ 1.81
Antidilutive shares excluded from the computation of diluted shares:			
Restricted common stock	**—**	—	—
Stock options	**0.2**	0.2	0.7
Performance share units	**—**	—	—

The following table provides the changes in our outstanding common shares:

	2023	2022	2021
		(In millions)	
Balance at January 1	**306.2**	309.7	307.0
Activity related to restricted stock awards, net	**0.4**	0.5	0.7
Stock options exercised	**0.2**	0.9	1.5
PSUs vested	**0.4**	0.5	0.5
Shares repurchased	**—**	(5.4)	—
Balance at December 31	**307.2**	306.2	309.7

Common Stock Repurchase Plan:

On March 1, 2023, our Board of Directors approved a new authorization for the repurchase of our common stock in an aggregate amount of up to $1 billion. This new authorization replaced our previous repurchase authorization which was fully utilized at the end of 2022. There were no shares of our common stock repurchased during 2023 or 2021. During 2022, we repurchased approximately 5.4 million shares of our common stock for $650 million ($20 million was paid subsequent to December 31, 2022). Shares of common stock repurchased are retired upon settlement of the trade.

Common Stock Dividends:

Cash dividends declared on common stock totaled $1.75 per share in 2023 (2022: $1.50 per share; 2021: $1.00 per share).

16. Supplementary Cash Flow Information

The following information supplements the *Statement of Consolidated Cash Flows*:

	2023	2022	2021
		(In millions)	
Cash Flows From Operating Activities			
Interest paid	**$ (470)**	$ (486)	$ (459)
Net income taxes (paid) refunded	**(71)**	(1,036)	(16)
Cash Flows From Investing Activities			
Additions to property, plant and equipment – E&P:			
Capital expenditures incurred – E&P	**$ (4,033)**	$ (2,589)	$ (1,698)
Increase (decrease) in related liabilities	**149**	102	114
Additions to property, plant and equipment – E&P	**$ (3,884)**	$ (2,487)	$ (1,584)
Additions to property, plant and equipment – Midstream:			
Capital expenditures incurred – Midstream	**$ (246)**	$ (232)	$ (183)
Increase (decrease) in related liabilities	**22**	(6)	20
Additions to property, plant and equipment – Midstream	**$ (224)**	$ (238)	$ (163)

17. Guarantees, Contingencies and Commitments

Guarantees and Contingencies

We are subject to loss contingencies with respect to various claims, lawsuits and other proceedings. A liability is recognized in our consolidated financial statements when it is probable that a loss has been incurred and the amount can be reasonably estimated. If the risk of loss is probable, but the amount cannot be reasonably estimated or the risk of loss is only reasonably possible, a liability is not accrued; however, we disclose the nature of those contingencies. We cannot predict with certainty if, how or when existing claims, lawsuits and proceedings will be resolved or what the eventual relief, if any, may be, particularly for proceedings that are in their early stages of development or where plaintiffs seek indeterminate damages.

We, along with many companies that have been or continue to be engaged in refining and marketing of gasoline, have been a party to lawsuits and claims related to the use of MTBE in gasoline. A series of similar lawsuits, many involving water utilities or governmental entities, were filed in jurisdictions across the United States against producers of MTBE and petroleum refiners who produced gasoline containing MTBE, including us. The principal allegation in all cases was that gasoline containing MTBE was a defective product and that these producers and refiners are strictly liable in proportion to their share of the gasoline market for damage to groundwater resources and are required to take remedial action to ameliorate the alleged effects on the environment of releases of MTBE. The majority of the cases asserted against us have been settled. There are two remaining active cases, filed by Pennsylvania and Maryland. In June 2014, the Commonwealth of Pennsylvania filed a lawsuit alleging that we and all major oil companies with operations in Pennsylvania, have damaged the groundwater by introducing thereto gasoline with MTBE. The Pennsylvania suit has been forwarded to the existing MTBE multidistrict litigation pending in the Southern District of New York. In December 2017, the State of Maryland filed a lawsuit alleging that we and other major oil companies damaged the groundwater in Maryland by introducing thereto gasoline with MTBE. The suit, filed in Maryland state court, was served on us in January 2018 and has been removed to federal court by the defendants.

In March 2014, we received an Administrative Order from the EPA requiring us and 26 other parties to undertake the Remedial Design for the remedy selected by the EPA for the Gowanus Canal Superfund Site in Brooklyn, New York. Our alleged liability derives from our former ownership and operation of a fuel oil terminal and connected shipbuilding and repair facility adjacent to the Canal. The remedy selected by the EPA includes dredging of surface sediments and the placement of a cap over the deeper sediments throughout the Canal and in-situ stabilization of certain contaminated sediments that will remain in place below the cap. The EPA's original estimate was that this remedy would cost $506 million; however, the ultimate costs that will be incurred in connection with the design and implementation of the remedy remain uncertain. We have complied with the EPA's March 2014 Administrative Order and contributed funding for the Remedial Design based on an allocation of costs among the parties determined by a third-party expert. In January 2020, we received an additional Administrative Order from the EPA requiring us and several other parties to begin Remedial Action along the uppermost portion of the Canal. We intend to comply with this Administrative Order. The remediation work began in the fourth quarter of 2020. Based on currently known facts and circumstances, we do not believe that this matter will result in a significant liability to us, and the costs will continue to be allocated amongst the parties, as they were for the Remedial Design.

From time to time, we are involved in other judicial and administrative proceedings relating to environmental matters. We periodically receive notices from the EPA that we are a "potential responsible party" under the Superfund legislation with respect to various waste disposal sites. Under this legislation, all potentially responsible parties may be jointly and severally liable. For any site for which we have received such a notice, the EPA's claims or assertions of liability against us relating to these sites have not been fully developed, or the EPA's claims have been settled or a settlement is under consideration, in all cases for amounts that are not material. Beginning in 2017, certain states, municipalities and private associations in California, Delaware, Maryland, Rhode Island and South Carolina separately filed lawsuits against oil, gas and coal producers, including us, for alleged damages purportedly caused by climate change. These proceedings include claims for monetary damages and injunctive relief. Beginning in 2013, various parishes in Louisiana filed suit against approximately 100 oil and gas companies, including us, alleging that the companies' operations and activities in certain fields violated the State and Local Coastal Resource Management Act of 1978, as amended, and caused contamination, subsidence and other environmental damages to land and water bodies located in the coastal zone of Louisiana. The plaintiffs seek, among other things, the payment of the costs necessary to clear, re-vegetate and otherwise restore the allegedly impacted areas. The ultimate impact of such climate and other aforementioned environmental proceedings, and of any related proceedings by private parties, on our business or accounts cannot be predicted at this time due to the large number of other potentially responsible parties and the speculative nature of clean-up cost estimates.

Hess Corporation and its subsidiary HONX, Inc. have been named as defendants in various personal injury claims alleging exposure to asbestos and/or other alleged toxic substances while working at a former refinery (owned and operated by subsidiaries or related entities) located in St. Croix, U.S. Virgin Islands. On April 28, 2022, HONX, Inc. initiated a Chapter 11 § 524G process in the United States Bankruptcy Court for the Southern District of Texas, Houston Division, to resolve these asbestos-related claims. In February 2023, Hess, HONX, Inc., the Unsecured Creditors' Committee, and counsel representing claimants, reached a mediated resolution of the matter, contingent upon ongoing negotiations with the Future Claimants Representative (FCR), final approvals of all parties and confirmation by the Bankruptcy Court. As of December 31, 2023, following agreement with the FCR, we increased our reserve to a total of $153 million for the amounts expected to be funded to the § 524G trust established for the settlement of all current and future claims. The Bankruptcy Court and U.S. Federal District Court confirmed the HONX Bankruptcy Plan on February 16, 2024.

We are also involved in six claims in federal and state courts in North Dakota related to post-production deductions from royalty and working interest payments. The plaintiffs in these cases assert that we take unauthorized or excessive post-production deductions from royalty or working interest payments for various oil and gas processing and transportation related costs and expenses. These plaintiffs seek reimbursement for allegedly underpaid revenue. It is our position that these costs and expenses are actual, reasonable, necessary, and authorized by the respective leases and North Dakota law. We believe that based on the facts and circumstances of these claims and because we have viable defenses, loss is not probable and the ultimate impact of these claims on our business or accounts cannot be estimated at this time due to the early stages of the proceedings and the speculative and indeterminate damages.

We may also be exposed to future decommissioning liabilities for divested assets in the event the current or future owners of facilities previously owned by us are determined to be unable to perform such actions, whether due to bankruptcy or otherwise. We cannot predict with certainty if, how or when such proceedings will be resolved or what the eventual relief, if any, may be, particularly for proceedings that are in their early stages of development or where plaintiffs seek indeterminate damages. Numerous issues may need to be resolved, including through potentially lengthy discovery and determination of important factual matters before a loss or range of loss can be reasonably estimated for any proceeding.

Subject to the foregoing, in management's opinion, based upon currently known facts and circumstances, the outcome of lawsuits, claims and proceedings, including the matters disclosed above, is not expected to have a material adverse effect on our financial condition, results of operations or cash flows. However, we could incur judgments, enter into settlements, or revise our opinion regarding the outcome of certain matters, and such developments could have a material adverse effect on our results of operations in the period in which the amounts are accrued and our cash flows in the period in which the amounts are paid.

Unconditional Purchase Obligations and Commitments

The following table shows aggregate information for certain unconditional purchase obligations and commitments at December 31, 2023, which are not included elsewhere within these *Consolidated Financial Statements*:

		Payments Due by Period					
	Total	2024	2025	2026	2027	2028	Thereafter
				(In millions)			
Capital expenditures	$ 7,472	$ 2,371	$ 2,106	$ 1,757	$ 774	$ 371	$ 93
Operating expenses	762	238	107	55	50	63	249
Transportation and related contracts	2,243	298	260	286	277	261	861

18. Segment Information

We currently have two operating segments, E&P and Midstream. The E&P operating segment explores for, develops, produces, purchases and sells crude oil, NGL and natural gas. Production operations over the three years ended December 31, 2023 were in Guyana, the U.S., Malaysia and the JDA, Libya (sold in November 2022) and Denmark (sold in August 2021). The Midstream operating segment provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGL; gathering, terminaling, loading and transporting crude oil and NGL; storing and terminaling propane, and water handling services primarily in the Bakken shale play of North Dakota. All unallocated costs are reflected under Corporate, Interest and Other.

The following table presents operating segment financial data (in millions):

	Exploration and Production	Midstream	Corporate, Interest and Other	Eliminations	Total
2023					
Sales and other operating revenues	**$ 10,500**	**$ 11**	**$ —**	**$ —**	**$ 10,511**
Intersegment revenues	**—**	**1,338**	**—**	**(1,338)**	**—**
Total sales and other operating revenues	**$ 10,500**	**$ 1,349**	**$ —**	**$ (1,338)**	**$ 10,511**
Net income (loss) attributable to Hess Corporation	**$ 1,601**	**$ 252**	**$ (471)**	**$ —**	**$ 1,382**
Interest expense	**—**	**179**	**299**	**—**	**478**
Depreciation, depletion and amortization	**1,852**	**193**	**1**	**—**	**2,046**
Impairment and other	**82**	**—**	**—**	**—**	**82**
Provision for income taxes	**695**	**38**	**—**	**—**	**733**
Investment in affiliates	**76**	**90**	**—**	**—**	**166**
Identifiable assets	**17,931**	**3,984**	**2,092**	**—**	**24,007**
Capital expenditures	**4,033**	**246**	**—**	**—**	**4,279**
2022					
Sales and other operating revenues	$ 11,324	$ —	$ —	$ —	$ 11,324
Intersegment revenues	—	1,273	—	(1,273)	—
Total sales and other operating revenues	$ 11,324	$ 1,273	$ —	$ (1,273)	$ 11,324
Net income (loss) attributable to Hess Corporation	$ 2,396	$ 269	$ (569)	$ —	$ 2,096
Interest expense	—	150	343	—	493
Depreciation, depletion and amortization	1,520	181	2	—	1,703
Impairment and other	54	—	—	—	54
Provision for income taxes	1,072	27	—	—	1,099
Investment in affiliates	88	94	1	—	183
Identifiable assets	15,022	3,775	2,898	—	21,695
Capital expenditures	2,589	232	—	—	2,821
2021					
Sales and other operating revenues	$ 7,473	$ —	$ —	$ —	$ 7,473
Intersegment revenues	—	1,204	—	(1,204)	—
Total sales and other operating revenues	$ 7,473	$ 1,204	$ —	$ (1,204)	$ 7,473
Net income (loss) attributable to Hess Corporation	$ 770	$ 286	$ (497)	$ —	$ 559
Interest expense	—	105	376	—	481
Depreciation, depletion and amortization	1,361	166	1	—	1,528
Impairment and other	147	—	—	—	147
Provision for income taxes	585	15	—	—	600
Capital expenditures	1,698	183	—	—	1,881

Corporate, Interest and Other had interest income of $82 million in 2023 (2022: $32 million, 2021: $1 million) which is included in *Other, net* in the *Statement of Consolidated Income.*

The following table presents financial information by major geographic area:

	United States	Guyana	Malaysia and JDA	Other (a)	Corporate, Interest and other	Total
	(In millions)					
2023						
Sales and Other Operating Revenues	**$ 6,092**	**$ 3,494**	**$ 925**	**$ —**	**$ —**	**$ 10,511**
Property, Plant and Equipment (Net) (b)	**10,554**	**5,957**	**872**	**42**	**7**	**17,432**
2022						
Sales and Other Operating Revenues	$ 7,214	$ 2,636	$ 873	$ 601	$ —	$ 11,324
Property, Plant and Equipment (Net) (b)	9,937	4,042	1,065	46	8	15,098
2021						
Sales and Other Operating Revenues	$ 5,378	$ 754	$ 738	$ 603	$ —	$ 7,473

(a) Other includes our interests in Libya (sold in November 2022), Denmark (sold in August 2021), Suriname and Canada.
(b) Property, plant and equipment in the United States in 2023 includes $7,325 million (2022: $6,764 million) attributable to the E&P segment and $3,229 million (2022: $3,173 million) attributable to the Midstream segment.

19. Financial Risk Management Activities

In the normal course of our business, we are exposed to commodity risks related to changes in the prices of crude oil and natural gas, as well as changes in interest rates and foreign currency values. In the disclosures that follow, corporate financial risk management activities refer to the mitigation of these risks through hedging activities. We maintain a control environment for all of our financial risk management activities under the direction of our Chief Risk Officer. Our Treasury department is responsible for administering foreign exchange rate and interest rate hedging programs using similar controls and processes, where applicable. Hedging strategies are reviewed annually by the Audit Committee of the Board of Directors.

Corporate Financial Risk Management Activities: Financial risk management activities include transactions designed to reduce risk in the selling prices of crude oil or natural gas we produce or reduce our exposure to foreign currency or interest rate movements. Generally, futures, swaps or option strategies may be used to fix the forward selling price, or establish a floor price or a range banded with a floor and ceiling price, for a portion of our crude oil or natural gas production. Forward contracts or swaps may also be used to purchase certain currencies in which we conduct business with the intent of reducing exposure to foreign currency fluctuations. At December 31, 2023, these forward contracts relate to the British Pound and Malaysian Ringgit. Interest rate swaps may be used to convert interest payments on certain long-term debt from fixed to floating rates.

The notional amounts of outstanding financial risk management derivative contracts were as follows:

	December 31, 2023	December 31, 2022
	(In millions)	
Foreign exchange forwards and swaps	$ 226	$ 177
Interest rate swaps	$ 100	$ 100

The table below reflects the gross and net fair values of risk management derivative instruments:

	Assets	Liabilities
	(In millions)	
December 31, 2023		
Derivative Contracts Designated as Hedging Instruments:		
Interest rate swaps	$ —	$ (2)
Total derivative contracts designated as hedging instruments	—	(2)
Derivative Contracts Not Designated as Hedging Instruments:		
Foreign exchange forwards and swaps	—	(6)
Total derivative contracts not designated as hedging instruments	—	(6)
Gross fair value of derivative contracts	—	(8)
Gross amount offset in the Consolidated Balance Sheet	—	—
Net Amounts Presented in the Consolidated Balance Sheet	$ —	$ (8)
December 31, 2022		
Derivative Contracts Designated as Hedging Instruments:		
Interest rate swaps	—	(4)
Total derivative contracts designated as hedging instruments	—	(4)
Derivative Contracts Not Designated as Hedging Instruments:		
Foreign exchange forwards and swaps	—	(2)
Total derivative contracts not designated as hedging instruments	—	(2)
Gross fair value of derivative contracts	—	(6)
Gross amount offset in the Consolidated Balance Sheet	—	—
Net Amounts Presented in the Consolidated Balance Sheet	$ —	$ (6)

At December 31, 2023 and 2022, the fair value of our interest rate swaps is presented within *Accrued liabilities* and *Other liabilities and deferred credits*, respectively, in our *Consolidated Balance Sheet*. The fair value of our foreign exchange forwards and swaps is presented within *Accrued liabilities* in our *Consolidated Balance Sheet*. All fair values in the table above are based on Level 2 inputs.

Crude oil price hedging contracts decreased *Sales and other operating revenues* by $190 million in 2023 (2022: decrease of $585 million; 2021: decrease of $243 million). The change in fair value of interest rate swaps was an increase of $2 million in 2023 (2022: $6 million decrease; 2021: $3 million decrease) with a corresponding adjustment in the carrying value of the hedged fixed-rate debt. We recognized net foreign exchange gains of $4 million in 2023 (2022: $16 million losses; 2021: $3 million losses). Offsetting these net foreign exchange gains were net losses from our foreign exchange derivative contracts, that are not designated as hedges, of $2 million in 2023 (2022: $14 million gains; 2021: $1 million gains). Foreign exchange gains and losses, and the gains and losses on our foreign exchange derivative contracts, are recorded in *Other, net* in the *Statement of Consolidated Income*.

Credit Risk: We are exposed to credit risks that may at times be concentrated with certain counterparties, groups of counterparties or customers. Accounts receivable are generated from a diverse domestic and international customer base. At December 31, 2023, our accounts receivable were concentrated with the following counterparty industry segments: Integrated companies 40%, Independent E&P companies 37%, Refining and marketing companies 12%, Storage and transportation companies 4%, National oil companies 1%, and Others 6%. We reduce risk related to certain counterparties, where applicable, by using master netting arrangements and requiring collateral, generally cash or letters of credit.

At December 31, 2023, we had outstanding letters of credit totaling $88 million (2022: $83 million).

Fair Value Measurement: At December 31, 2023, our total long-term debt, which was substantially comprised of fixed rate debt instruments, had a carrying value of $8,613 million and a fair value of $9,006 million, based on Level 2 inputs in the fair value measurement hierarchy. We also have short-term financial instruments, primarily cash equivalents, accounts receivable and accounts payable, for which the carrying value approximated fair value at December 31, 2023 and December 31, 2022.

20. Subsequent Event

In February 2024, Hess Midstream LP completed an underwritten public equity offering of 11.5 million Hess Midstream LP Class A shares held by an affiliate of GIP. Hess did not receive any proceeds from this transaction. After giving effect to this transaction, public shareholders of Class A shares of Hess Midstream LP own approximately 35%, GIP owns approximately 27%, and Hess owns approximately 38% of the consolidated entity on an as-exchanged basis.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTARY OIL AND GAS DATA (UNAUDITED)

The *Supplementary Oil and Gas Data* that follows is presented in accordance with ASC 932, *Disclosures about Oil and Gas Producing Activities,* and includes (1) costs incurred, capitalized costs and results of operations relating to oil and gas producing activities, (2) net proved oil and gas reserves and (3) a standardized measure of discounted future net cash flows relating to proved oil and gas reserves, including a reconciliation of changes therein.

Costs Incurred in Oil and Gas Producing Activities

For the Years Ended December 31	Total	United States	Guyana	Malaysia and JDA	Other (a)
			(In millions)		
2023					
Property acquisitions					
Unproved	**$ 8**	**$ 8**	**$ —**	**$ —**	**$ —**
Proved	**—**	**—**	**—**	**—**	**—**
Exploration	**484**	**167**	**271**	**5**	**41**
Production and development capital expenditures (b) (c)	**3,885**	**1,424**	**2,258**	**203**	**—**
2022					
Property acquisitions					
Unproved	$ 1	$ 1	$ —	$ —	$ —
Proved	—	—	—	—	—
Exploration	489	158	259	11	61
Production and development capital expenditures (b)	2,449	970	1,167	303	9
2021					
Property acquisitions					
Unproved	$ 24	$ 4	$ 20	$ —	$ —
Proved	—	—	—	—	—
Exploration	368	92	250	7	19
Production and development capital expenditures (b) (c)	1,645	653	820	157	15

(a) Other includes our interests in Libya (sold in November 2022), Denmark (sold in August 2021), Suriname and Canada.
(b) Includes an increase for net accruals and revisions of asset retirement obligations of $201 million in 2023 (2022: $218 million increase; 2021: $208 million increase).
(c) Net accruals for asset retirement obligations in the United States exclude a charge of $82 million in 2023 (2021: $147 million) related to our former interests in the West Delta Field in the Gulf of Mexico which we sold to a Fieldwood predecessor in 2004. See Note 8, Asset Retirement Obligations in the Notes to Consolidated Financial Statements.

Capitalized Costs Relating to Oil and Gas Producing Activities

	At December 31, 2023	2022
	(In millions)	
Unproved properties	**$ 103**	$ 149
Proved properties	**2,660**	2,660
Wells, equipment and related facilities	**29,159**	25,182
Total costs	**31,922**	27,991
Less: Reserve for depreciation, depletion, amortization and lease impairment	**17,726**	16,074
Net Capitalized Costs	**$ 14,196**	$ 11,917

Results of Operations for Oil and Gas Producing Activities

The results of operations shown below exclude non-oil and gas producing activities, primarily gains (losses) on sales of oil and gas properties, sales of purchased crude oil, NGL and natural gas from third parties, interest expense and non-operating income. Revenue from net production volumes include crude oil hedging results and are net of payments for unutilized committed transportation capacity. Therefore, these results are on a different basis than the net income (loss) from E&P operations reported in Management's Discussion and Analysis of Financial Condition and Results of Operations and in *Note 18, Segment Information* in the *Notes to Consolidated Financial Statements.*

For the Years Ended December 31	Total	United States	Guyana (a)	Malaysia and JDA	Other (b)
			(In millions)		
2023					
Revenue from net production volumes	**$ 7,761**	**$ 3,462**	**$ 3,374**	**$ 925**	**$ —**
Costs and Expenses					
Operating costs and expenses	**1,479**	**901**	**402**	**176**	**—**
Production and severance taxes	**216**	**206**	**—**	**10**	**—**
Midstream tariffs	**1,245**	**1,245**	**—**	**—**	**—**
Exploration expenses, including dry holes and lease impairment	**317**	**170**	**97**	**1**	**49**
General and administrative expenses	**254**	**213**	**26**	**15**	**—**
Depreciation, depletion and amortization	**1,852**	**904**	**526**	**422**	**—**
Impairment and other	**82**	**82**	**—**	**—**	**—**
Total Costs and Expenses	**5,445**	**3,721**	**1,051**	**624**	**49**
Results of Operations Before Income Taxes	**2,316**	**(259)**	**2,323**	**301**	**(49)**
Provision (benefit) for income taxes	**696**	**—**	**628**	**67**	**1**
Results of Operations	**$ 1,620**	**$ (259)**	**$ 1,695**	**$ 234**	**$ (50)**
2022					
Revenue from net production volumes	$ 7,976	$ 4,076	$ 2,538	$ 873	$ 489
Costs and Expenses					
Operating costs and expenses	1,186	706	320	143	17
Production and severance taxes	255	242	—	13	—
Midstream tariffs	1,193	1,193	—	—	—
Exploration expenses, including dry holes and lease impairment	208	122	63	4	19
General and administrative expenses	224	189	18	16	1
Depreciation, depletion and amortization	1,520	810	394	297	19
Impairment and other	54	54	—	—	—
Total Costs and Expenses	4,640	3,316	795	473	56
Results of Operations Before Income Taxes	3,336	760	1,743	400	433
Provision (benefit) for income taxes	991	—	514	32	445
Results of Operations	$ 2,345	$ 760	$ 1,229	$ 368	$ (12)
2021					
Revenue from net production volumes	$ 5,621	$ 3,638	$ 738	$ 738	$ 507
Costs and Expenses					
Operating costs and expenses (c)	1,073	718	196	106	53
Production and severance taxes	172	166	—	6	—
Midstream tariffs	1,094	1,094	—	—	—
Exploration expenses, including dry holes and lease impairment	162	102	35	7	18
General and administrative expenses	191	162	12	11	6
Depreciation, depletion and amortization (c)	1,426	1,085	109	205	27
Impairment and other	147	147	—	—	—
Total Costs and Expenses	4,265	3,474	352	335	104
Results of Operations Before Income Taxes	1,356	164	386	403	403
Provision (benefit) for income taxes	534	—	119	31	384
Results of Operations	$ 822	$ 164	$ 267	$ 372	$ 19

(a) Production commenced from Liza Phase 1 in December 2019, Liza Phase 2 in February 2022 and Payara in November 2023. Operating costs and expenses also include pre-development costs from the operator for future phases of development and Hess internal costs.

(b) Other includes our interests in Libya (sold in November 2022), Denmark (sold in August 2021), Suriname and Canada.

(c) Operating costs and expenses and depreciation, depletion and amortization, in the United States, include $108 million and $65 million, respectively, related to the cost of 4.2 million barrels of crude oil stored on two VLCCs at December 31, 2020 that were sold in 2021.

Proved Oil and Gas Reserves

Our proved oil and gas reserves are calculated in accordance with the Securities and Exchange Commission (SEC) regulations and the requirements of the Financial Accounting Standards Board. Proved oil and gas reserves are quantities, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from known reservoirs under existing economic conditions, operating methods and government regulations. Our estimation of net recoverable quantities of liquid hydrocarbons and natural gas is a highly technical process performed by our internal teams of geoscience and reservoir engineering professionals. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of June 25, 2019)." The method or combination of methods used in the analysis of each reservoir is based on the maturity of the reservoir, the completeness of the subsurface data available at the time of the estimate, the stage of reservoir development and the production history. Subsurface data used included well logs, reservoir core and fluid samples, production and pressure testing, static and dynamic pressure information, and reservoir surveillance. Where applicable, reliable technologies may be used in reserve estimation, as defined in the SEC regulations. These technologies, including computational methods, must have been field tested and demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In some cases, where appropriate, use of empirical and analytical methods, combined with analog data were used. Analytic tools, including reservoir simulation, geologic modeling and seismic processing, have been used in the interpretation of the subsurface data. These technologies were used to increase the quality and confidence in the reserves estimates.

In order for reserves to be classified as proved, any required government approvals must be obtained and depending on the cost of the project, either senior management or the Board of Directors must commit to fund the development. Our proved reserves are subject to certain risks and uncertainties, which are discussed in *Part 1, Item 1A. Risk Factors* of this Form 10-K.

Internal Controls

The Corporation maintains internal controls over its oil and gas reserve estimation processes, which are administered by our Global Reserves group and our Chief Financial Officer. Estimates of reserves are prepared by technical staff who work directly with the oil and gas properties using industry standard reserve estimation principles, definitions and methodologies. Each year, reserve estimates of the Corporation's assets are subject to internal technical audits and reviews. In addition, an independent third-party reserve engineer reviews and audits a significant portion of the Corporation's reported reserves (see pages 94 through 99). Reserve estimates are reviewed by senior management and the Board of Directors.

Qualifications

The person primarily responsible for overseeing the preparation of the Corporation's oil and gas reserves during 2023 was the Director, Global Reserves. He is a member of the Society of Petroleum Engineers and has over 20 years of experience in the oil and gas industry with a MSc degree in Petroleum Engineering. His experience has been primarily focused on oil and gas subsurface understanding and reserves estimation in both domestic and international areas. He is also responsible for the Corporation's Global Reserves group, which is the internal organization that establishes the policies and processes used within the operating units to estimate reserves and perform internal technical reserve audits and reviews.

Reserves Audit

We engaged the consulting firm of DeGolyer and MacNaughton (D&M) to perform an audit of the internally prepared reserve estimates on certain fields aggregating approximately 89% of 2023 year-end reported reserve quantities on a barrel of oil equivalent basis (2022: 89%). The purpose of this audit was to provide additional assurance on the reasonableness of internally prepared reserve estimates and compliance with SEC regulations. The D&M report, dated February 7, 2024, on the Corporation's estimated oil and gas reserves was prepared using standard geological and engineering methods generally recognized in the petroleum industry. D&M is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over 70 years. D&M's letter report on the Corporation's December 31, 2023 oil and gas reserves is included as an exhibit to this Form 10-K. While the D&M report should be read in its entirety, the report concludes that for the properties reviewed by D&M, the total net proved reserve estimates prepared by Hess and independently evaluated by D&M, in the aggregate, differed by approximately 1.3% (2022: approximately 2.6%) of total audited net proved reserves on a barrel of oil equivalent basis. The report also includes among other information, the qualifications of the technical person primarily responsible for overseeing the reserve audit.

Crude Oil Prices Used to Estimate Proved Reserves

Proved reserves are calculated using the average price during the twelve-month period before December 31 determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the year, unless prices are defined by contractual agreements, excluding escalations based on future conditions. Crude oil prices used in the determination of proved reserves at December 31, 2023 were $78.10 per barrel for WTI (2022: $94.13; 2021: $66.34) and $82.51 per barrel for Brent (2022:

$97.98; 2021: $68.92). New York Mercantile Exchange (NYMEX) natural gas prices used were $2.75 per mcf in 2023 (2022: $6.44; 2021: $3.68).

At December 31, 2023, spot prices closed at $71.65 per barrel for WTI and $77.59 per barrel for Brent. If crude oil prices in 2024 are at levels below that used in determining 2023 proved reserves, we may recognize negative revisions to our December 31, 2024 proved undeveloped reserves. In addition, we may recognize negative revisions to proved developed reserves, which can vary significantly by asset due to differing operating cost structures. Conversely, price increases in 2024 above those used in determining 2023 proved reserves could result in positive revisions to proved developed and proved undeveloped reserves at December 31, 2024. It is difficult to estimate the magnitude of any potential net negative or positive change in proved reserves at December 31, 2024, due to numerous currently unknown factors, including 2024 crude oil prices, the amount of any additions to proved reserves, positive or negative revisions in proved reserves related to 2024 reservoir performance, the levels to which industry costs will change in response to 2024 crude oil prices, and management's plans as of December 31, 2024 for developing proved undeveloped reserves.

Following are the Corporation's proved reserves:

	Crude Oil & Condensate					Natural Gas Liquids	
	United States	Guyana	Malaysia and JDA	Other (a)	Total	United States	Total
	(Millions of bbls)					(Millions of bbls)	
Net Proved Reserves							
At January 1, 2021	401	204	6	134	745	162	162
Revisions of previous estimates	16	3	—	—	19	23	23
Extensions, discoveries and other additions	161	9	—	1	171	73	73
Sales of minerals in place	(40)	—	—	(27)	(67)	(6)	(6)
Production	(40)	(11)	(1)	(8)	(60)	(19)	(19)
At December 31, 2021	498	205	5	100	808	233	233
Revisions of previous estimates	(35)	4	(1)	(1)	(33)	10	10
Extensions, discoveries and other additions	55	100	—	—	155	22	22
Sales of minerals in place	—	—	—	(93)	(93)	—	—
Production	(35)	(29)	(1)	(6)	(71)	(20)	(20)
At December 31, 2022	483	280	3	—	766	245	245
Revisions of previous estimates	**(19)**	**71**	**1**	**—**	**53**	**26**	**26**
Extensions, discoveries and other additions	**43**	**78**	**1**	**—**	**122**	**16**	**16**
Sales of minerals in place	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Production	**(38)**	**(42)**	**(2)**	**—**	**(82)**	**(25)**	**(25)**
At December 31, 2023	**469**	**387**	**3**	**—**	**859**	**262**	**262**
Net Proved Developed Reserves							
At January 1, 2021	282	72	4	134	492	120	120
At December 31, 2021	283	65	3	100	451	138	138
At December 31, 2022	277	116	3	—	396	156	156
At December 31, 2023	**265**	**201**	**3**	**—**	**469**	**173**	**173**
Net Proved Undeveloped Reserves							
At January 1, 2021	119	132	2	—	253	42	42
At December 31, 2021	215	140	2	—	357	95	95
At December 31, 2022	206	164	—	—	370	89	89
At December 31, 2023	**204**	**186**	**—**	**—**	**390**	**89**	**89**

(a) Other includes our interests in Libya (sold in November 2022) and Denmark (sold in August 2021).

	Natural Gas					Total				
	United States	Guyana (b)	Malaysia and JDA	Other (c)	Total	United States	Guyana	Malaysia and JDA	Other (c)	Total
	(Millions of mcf)					(Millions of boe)				
Net Proved Reserves										
At January 1, 2021	653	83	675	165	1,576	672	218	118	162	1,170
Revisions of previous estimates	138	(33)	(42)	—	63	62	(3)	(6)	—	53
Extensions, discoveries and other additions	282	—	27	—	309	281	9	4	1	295
Sales of minerals in place	(44)	—	—	(63)	(107)	(53)	—	—	(38)	(91)
Production (a)	(94)	(2)	(135)	(4)	(235)	(75)	(11)	(23)	(9)	(118)
At December 31, 2021 (d)	935	48	525	98	1,606	887	213	93	116	1,309
Revisions of previous estimates	57	17	(15)	(1)	58	(16)	7	(3)	(1)	(13)
Extensions, discoveries and other additions	92	29	1	—	122	92	105	—	—	197
Sales of minerals in place	—	—	—	(94)	(94)	—	—	—	(109)	(109)
Production (a)	(80)	(3)	(136)	(3)	(222)	(68)	(30)	(24)	(6)	(128)
At December 31, 2022 (d)	1,004	91	375	—	1,470	895	295	66	—	1,256
Revisions of previous estimates	**16**	**18**	**41**	**—**	**75**	**10**	**74**	**8**	**—**	**92**
Extensions, discoveries and other additions	**65**	**81**	**38**	**—**	**184**	**70**	**92**	**7**	**—**	**169**
Sales of minerals in place	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Production (a)	**(93)**	**(5)**	**(139)**	**—**	**(237)**	**(79)**	**(43)**	**(25)**	**—**	**(147)**
At December 31, 2023 (d)	**992**	**185**	**315**	**—**	**1,492**	**896**	**418**	**56**	**—**	**1,370**
Net Proved Developed Reserves										
At January 1, 2021	490	36	543	165	1,234	484	78	94	162	818
At December 31, 2021	568	17	394	98	1,077	516	68	69	116	769
At December 31, 2022	648	37	304	—	989	541	122	54	—	717
At December 31, 2023	**656**	**71**	**288**	**—**	**1,015**	**547**	**213**	**51**	**—**	**811**
Net Proved Undeveloped Reserves										
At January 1, 2021	163	47	132	—	342	188	140	24	—	352
At December 31, 2021	367	31	131	—	529	371	145	24	—	540
At December 31, 2022	356	54	71	—	481	354	173	12	—	539
At December 31, 2023	**336**	**114**	**27**	**—**	**477**	**349**	**205**	**5**	**—**	**559**

(a) Natural gas production in 2023 includes 17 million mcf used for fuel (2022: 14 million mcf; 2021: 19 million mcf).
(b) Guyana natural gas reserves at December 31, 2023 reflect natural gas to be sold from the Liza Field to supply the 300 megawatt onshore power plant that will be constructed and operated by the Government of Guyana, and natural gas that will be consumed for fuel. Guyana natural gas reserves at December 31, 2022 and 2021 reflect natural gas that will be consumed for fuel.
(c) Other includes our interests in Libya (sold in November 2022) and Denmark (sold in August 2021).
(d) Natural gas to be consumed as fuel represents less than 3% of total proved reserves on a barrel of oil equivalent basis at December 31, 2023, 2022 and 2021.

Extensions, discoveries and other additions (‘Additions’)

2023: Total Additions were 169 million boe, of which 15 million boe (5 million barrels of crude oil, 2 million barrels of NGL and 48 million mcf of natural gas) related to proved developed reserves. Additions to proved developed reserves primarily resulted from drilling activity in the Bakken shale play in North Dakota and North Malay Basin, offshore Peninsula Malaysia. Additions to proved undeveloped reserves were 154 million boe (117 million barrels of crude oil, 14 million barrels of NGL and 136 million mcf of natural gas) and are discussed in further detail on page 98.

2022: Total Additions were 197 million boe, of which 14 million boe (9 million barrels of crude oil, 3 million barrels of NGL and 14 million mcf of natural gas) related to proved developed reserves. Additions to proved developed reserves primarily resulted from drilling activity in the Bakken shale play in North Dakota and the Stabroek Block, offshore Guyana. Additions to proved undeveloped reserves were 183 million boe (146 million barrels of crude oil, 19 million barrels of NGL and 108 million mcf of natural gas) and are discussed in further detail on page 98.

2021: Total Additions were 295 million boe, of which 25 million boe (14 million barrels of crude oil, 7 million barrels of NGL and 24 million mcf of natural gas) related to proved developed reserves. Additions to proved developed reserves primarily resulted from drilling activity in the Bakken shale play in North Dakota. Additions to proved undeveloped reserves were 270 million boe (157 million barrels of crude oil, 66 million barrels of NGL and 285 million mcf of natural gas) and are discussed in further detail on page 98.

Revisions of previous estimates

2023: Total revisions of previous estimates of proved reserves amounted to a net increase of 92 million boe, of which revisions of proved developed reserves amounted to a net increase of 80 million boe (45 million barrels of crude oil, 24 million barrels of NGL and 64 million mcf of natural gas). In the United States, net positive revisions to proved developed reserves from the Bakken were 13 million boe, comprised of positive revisions of 19 million boe and negative price revisions of 6 million boe. The positive revisions resulted from performance largely driven by an increase in gas volume estimates partially offset by an oil volume reduction, including updated shrinkage and yield factors (55%), and the capture of additional gas volumes (45%). In Guyana, net positive revisions to proved developed reserves of 66 million boe, primarily related to the Liza Field, resulted from improved recovery associated with water injection (60%), well performance (30%), and other positive revisions (10%), primarily increased natural gas for consumption. Revisions associated with proved undeveloped reserves are discussed in further detail on page 98.

2022: Total revisions of previous estimates of proved reserves amounted to a net decrease of 13 million boe, of which revisions of proved developed reserves amounted to a net increase of 20 million boe (20 million barrels of NGL and 82 million mcf of natural gas offset by a decrease of 14 million barrels of crude oil). In the United States, net positive revisions to proved developed reserves from the Bakken were 17 million boe relating to the capture of additional gas volumes (50%), well performance largely driven by an increase in gas volume estimates partially offset by an oil volume reduction (30%), and the impact of higher commodity prices (20%). In Guyana, net positive revisions to proved developed reserves totaled 2 million boe due to increased recovery based on performance and other positive revisions (7 million boe), partially offset by the impact of higher commodity prices on entitlement allocations in the production sharing contract (5 million boe). Revisions associated with proved undeveloped reserves are discussed in further detail on page 98.

2021: Total revisions of previous estimates of proved reserves amounted to a net increase of 53 million boe, of which revisions of proved developed reserves amounted to an increase of 73 million boe (31 million barrels of crude oil, 27 million barrels of NGL and 88 million mcf of natural gas). In the United States, net positive revisions to proved developed reserves from the Bakken of 68 million boe were due to higher commodity prices (39 million boe) and improved well performance (32 million boe), partially offset by other negative revisions of 3 million boe. In the Gulf of Mexico, positive revisions to proved developed reserves were 10 million boe, including 5 million boe of positive price revisions and 5 million boe of other revisions, primarily improved well performance. In Malaysia and JDA, net negative revisions to proved developed reserves were 6 million boe due to the impact of higher commodity prices on entitlement allocations in the production sharing contract at JDA (50%) and performance at North Malay Basin and JDA (50%). Revisions associated with proved undeveloped reserves are discussed in further detail on page 98.

Sales of minerals in place (‘Asset sales’)

2022: Asset sales relate to the divestiture of our working interest in the Waha Concession in Libya.

2021: Asset sales relate to the divestiture of our working interests in Denmark and our acreage interests in the Little Knife and Murphy Creek area of the Bakken.

Proved Undeveloped Reserves

Following are the Corporation's proved undeveloped reserves:

	United States	Guyana	Malaysia and JDA	Total
	(Millions of boe)			
Net Proved Undeveloped Reserves				
At January 1, 2021	188	140	24	352
Revisions of previous estimates	(16)	(4)	—	(20)
Extensions, discoveries and other additions	257	9	4	270
Transfers to proved developed reserves	(19)	—	(4)	(23)
Sales of minerals in place	(39)	—	—	(39)
At December 31, 2021	371	145	24	540
Revisions of previous estimates	(35)	5	(3)	(33)
Extensions, discoveries and other additions	81	102	—	183
Transfers to proved developed reserves	(63)	(79)	(9)	(151)
At December 31, 2022	354	173	12	539
Revisions of previous estimates	**(1)**	**8**	**5**	**12**
Extensions, discoveries and other additions	**61**	**92**	**1**	**154**
Transfers to proved developed reserves	**(65)**	**(68)**	**(13)**	**(146)**
At December 31, 2023	**349**	**205**	**5**	**559**

Extensions, discoveries and other additions ('Additions')

2023: In the United States, Additions in the Bakken shale play in North Dakota from new wells planned to be drilled in the next five years were 61 million boe. In Guyana, Additions of 92 million boe were due to the sanctioning of the Uaru Field development (63 million boe), extension of the proved area of the Yellowtail and Payara Fields (19 million boe) and approval of the gas to energy project (10 million boe).

2022: In the United States, Additions in the Bakken shale play in North Dakota from new wells planned to be drilled in the next five years were 79 million boe. In Guyana, Additions of 102 million boe were due to the sanctioning of the Yellowtail Field development (94 million boe), and extension of the proved area of the Payara Field (8 million boe).

2021: In the United States, Additions from the Bakken shale play in North Dakota were 257 million boe, which resulted from additional undeveloped well locations due to improved economic conditions, planned additional drilling activity, and development plan optimization. In Guyana, Additions of 9 million boe related to the deepening of the hydrocarbon contact for Liza Phase 2. In Malaysia and JDA, Additions were due to additional planned wells to be drilled.

Revisions of previous estimates

2023: In the United States, net negative reserve revisions of 1 million boe were primarily from the Bakken, which included a net decrease of 12 million boe related to wells moved outside the five-year development plan, partially offset by net positive revisions of 11 million boe primarily related to performance and updates to ownership interests. In Guyana, net positive reserve revisions of 8 million boe were primarily due to the impact of lower crude oil prices on entitlement allocations in the production sharing contract. In Malaysia and JDA, net positive revisions of 5 million boe primarily related to incorporating the latest drilling results.

2022: In the United States, net negative reserve revisions of 35 million boe were primarily from the Bakken, which included a net decrease of 26 million boe related to wells moved outside the five-year development plan, and other negative revisions of 9 million boe primarily related to performance and updates to ownership interests. In Guyana, net positive reserve revisions were 5 million boe, which included a net increase of 13 million boe primarily from increased recovery based on performance partially offset by negative revisions of 8 million boe related to the impact of higher crude oil prices on entitlement allocations in the production sharing contract.

2021: In the United States, net negative reserve revisions of 16 million boe were primarily from the Bakken, which included a decrease of 88 million boe largely related to wells moved outside the five-year development plan mainly based on optimization of drilling locations and other net negative revisions of 8 million boe, partially offset by positive revisions of 80 million boe related to higher prices. In Guyana, net negative reserve revisions were 4 million boe, which included negative revisions of 16 million boe related to the impact of higher crude oil prices on entitlement allocations in the production sharing contract and negative revisions of 3 million boe resulting from decreased natural gas for consumption. Positive revisions of 15 million boe in Guyana resulted from improved recovery associated with water and gas injection.

Transfers to proved developed reserves ('Transfers')

2023: Transfers from proved undeveloped reserves totaled 68 million boe in Guyana primarily related to the startup of production from the Payara Field development in November 2023 (61 million boe) and drilling activity (7 million boe). In the United States, Transfers of 65 million boe resulted from drilling activity in the Bakken. Transfers in 2023 were consistent with the development plan used to determine proved reserves at December 31, 2022, and in the Bakken we plan to continue to operate four rigs going forward. In Malaysia and JDA, Transfers of 13 million boe resulted from drilling activity.

2022: Transfers from proved undeveloped reserves totaled 79 million boe in Guyana primarily related to the startup of production from the Liza Phase 2 development in February 2022. In the United States, Transfers were 59 million boe in the Bakken and 4 million boe in the Gulf of Mexico resulting from drilling activity. Transfers in the United States for 2022 were consistent with the development plan used to determine proved reserves at December 31, 2021. In the Bakken, we added a fourth rig in July 2022, and we plan to operate four rigs going forward. In Malaysia and JDA, Transfers of 9 million boe resulted from drilling activity.

2021: Transfers from proved undeveloped reserves resulting from drilling activity included 19 million boe in the Bakken, and 4 million boe at JDA. Transfers in 2021 were consistent with the development plan used to determine proved reserves at December 31, 2020.

In 2023, capital expenditures of $2,198 million were incurred to convert proved undeveloped reserves to proved developed reserves (2022: $1,780 million; 2021: $190 million).

At December 31, 2023, projects that have proved reserves that have been classified as undeveloped for a period in excess of five years totaled 4 million boe, or less than 1% of total proved reserves, primarily related to the multi-phase offshore development at the North Malay Basin, offshore Peninsula Malaysia.

Production Sharing Contracts

The Corporation's proved reserves include crude oil and natural gas reserves relating to long-term agreements with governments or authorities in which the Corporation has the legal right to produce or has a revenue interest in the production. The Corporation's operations with these production sharing arrangements include those in Guyana, Malaysia, and the JDA. Proved reserves for each of the three years ended December 31, 2023, as well as volumes produced and received during 2023, 2022 and 2021 from these production sharing contracts are presented in the proved reserve tables on pages 95 and 96. Revisions resulting from the entitlement impact of price changes in production sharing contracts increased proved reserves by 10 million boe in 2023 (2022: 14 million boe decrease; 2021: 17 million boe decrease).

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Future net cash flows are calculated by applying prescribed oil and gas selling prices used in determining year-end reserve estimates (adjusted for price changes provided by contractual arrangements) to estimated future production of proved oil and gas reserves, less estimated future development costs (including future abandonment expenditures) and future production costs, which are based on year-end costs and existing economic assumptions. Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the pre-tax net cash flows, as well as including the effect of tax deductions and tax credits and allowances relating to the Corporation's proved oil and gas reserves. Future net cash flows are discounted at the prescribed rate of 10%.

The prices used for the discounted future net cash flows in 2023 were $78.10 per barrel for WTI (2022: $94.13; 2021: $66.34) and $82.51 per barrel for Brent (2022: $97.98; 2021: $68.92) and do not include the effects of commodity hedges. NYMEX natural gas prices used were $2.75 per mcf in 2023 (2022: $6.44; 2021: $3.68). Selling prices have in the past, and can in the future, fluctuate significantly. As a result, selling prices used in the disclosure of future net cash flows may not be representative of future selling prices. The discounted future net cash flow estimates do not include exploration expenses, interest expense or corporate general and administrative expenses. The amount of tax deductions, credits, and allowances relating to the Corporation's proved oil and gas reserves can change year to year due to factors including changes in proved reserves, variances in actual pre-tax cash flows from forecasted pre-tax cash flows in historical periods, and the impact to year-end carryforward tax attributes associated with deducting in the Corporation's income tax returns exploration expenses, interest expense, and corporate general and administrative expenses that are not contemplated in the standardized measure computations. The future net cash flow estimates could be materially different if other assumptions were used.

At December 31	Total	United States	Guyana	Malaysia and JDA	Other (a)
			(In millions)		
2023					
Future revenues	**$ 68,167**	**$ 33,514**	**$ 32,691**	**$ 1,962**	**$ —**
Less:					
Future production costs	**20,607**	**14,083**	**5,750**	**774**	—
Future development costs	**13,324**	**5,866**	**7,096**	**362**	—
Future income tax expenses	**7,373**	**2,953**	**4,299**	**121**	—
	41,304	**22,902**	**17,145**	**1,257**	—
Future net cash flows	**26,863**	**10,612**	**15,546**	**705**	—
Less: Discount at 10% annual rate	**12,130**	**6,254**	**5,817**	**59**	—
Standardized Measure of Discounted Future Net Cash Flows	**$ 14,733**	**$ 4,358**	**$ 9,729**	**$ 646**	**$ —**
2022					
Future revenues	$ 80,822	$ 50,373	$ 28,060	$ 2,389	$ —
Less:					
Future production costs	19,640	14,141	4,687	812	—
Future development costs	11,088	5,186	5,430	472	—
Future income tax expenses	11,795	7,308	4,307	180	—
	42,523	26,635	14,424	1,464	—
Future net cash flows	38,299	23,738	13,636	925	—
Less: Discount at 10% annual rate	17,382	12,677	4,589	116	—
Standardized Measure of Discounted Future Net Cash Flows	$ 20,917	$ 11,061	$ 9,047	$ 809	$ —
2021					
Future revenues	$ 55,788	$ 32,054	$ 13,940	$ 2,759	$ 7,035
Less:					
Future production costs	15,553	11,246	3,043	910	354
Future development costs	8,122	4,342	3,063	543	174
Future income tax expenses	11,257	3,625	1,516	151	5,965
	34,932	19,213	7,622	1,604	6,493
Future net cash flows	20,856	12,841	6,318	1,155	542
Less: Discount at 10% annual rate	9,603	7,073	2,091	193	246
Standardized Measure of Discounted Future Net Cash Flows	$ 11,253	$ 5,768	$ 4,227	$ 962	$ 296

(a) Other includes our interests in Libya (sold in November 2022).

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

For the Years Ended December 31	2023	2022	2021
		(In millions)	
Standardized Measure of Discounted Future Net Cash Flows at January 1	**$ 20,917**	$ 11,253	$ 3,585
Changes during the year:			
Sales and transfers of oil and gas produced during the year, net of production costs	**(4,821)**	(5,342)	(3,282)
Development costs incurred during the year	**3,684**	2,231	1,437
Net changes in prices and production costs	**(13,815)**	11,649	11,321
Net change in estimated future development costs	**(2,039)**	(2,156)	(1,695)
Extensions and discoveries (including improved recovery) of oil and gas reserves, less related costs	**3,202**	5,655	2,419
Revisions of previous oil and gas reserve estimates	**2,510**	(188)	461
Net purchases (sales) of minerals in place, before income taxes	**—**	(3,099)	(196)
Accretion of discount	**2,716**	1,338	578
Net change in income taxes	**2,425**	(450)	(3,477)
Revision in rate or timing of future production and other changes	**(46)**	26	102
Total	**(6,184)**	9,664	7,668
Standardized Measure of Discounted Future Net Cash Flows at December 31	**$ 14,733**	$ 20,917	$ 11,253

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Based upon their evaluation of the Corporation's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of December 31, 2023, John B. Hess, Chief Executive Officer, and John P. Rielly, Chief Financial Officer, concluded that these disclosure controls and procedures were effective as of December 31, 2023.

There was no change in internal controls over financial reporting identified in the evaluation required by paragraph (d) of Rules 13a-15 or 15d-15 in the quarter ended December 31, 2023 that has materially affected, or is reasonably likely to materially affect, internal controls over financial reporting.

Management's report on internal control over financial reporting and the attestation report on the Corporation's internal controls over financial reporting are included in *Item 8. Financial Statements and Supplementary Data* of this annual report on Form 10-K.

Item 9B. Other Information

During the three months ended December 31, 2023, none of our directors or officers (as defined in Rule 16a-1(f) under the Exchange Act) adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(a) of Regulation S-K.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

For information regarding our executive officers, see Part I of this Annual Report on Form 10-K. Additional information required by this item is incorporated herein by reference to the Corporation's definitive proxy statement for the 2024 annual meeting of stockholders.

The Corporation has adopted a Code of Business Conduct and Ethics applicable to the Corporation's directors, officers (including the Corporation's principal executive officer and principal financial officer) and employees. The Code of Business Conduct and Ethics is available on the Corporation's website. In the event that we amend or waive any of the provisions of the Code of Business Conduct and Ethics that relate to any element of the code of ethics definition enumerated in Item 406(b) of Regulation S-K, we intend to disclose the same on the Corporation's website at www.hess.com.

Item 11. Executive Compensation

Information relating to executive compensation is incorporated herein by reference to the Corporation's definitive proxy statement for the 2024 annual meeting of stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information pertaining to security ownership of certain beneficial owners and management is incorporated herein by reference to the Corporation's definitive proxy statement for the 2024 annual meeting of stockholders.

See Equity Compensation Plans in *Item 5. Market for the Registrant's Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities* for information pertaining to securities authorized for issuance under equity compensation plans.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information relating to this item is incorporated herein by reference to the Corporation's definitive proxy statement for the 2024 annual meeting of stockholders.

Item 14. Principal Accounting Fees and Services

Information relating to this item is incorporated herein by reference to the Corporation's definitive proxy statement for the 2024 annual meeting of stockholders.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are made a part of this Annual Report on Form 10-K:

1. and 2. Financial statements and financial statement schedules

The financial statements filed as part of this Annual Report on Form 10-K are listed in the accompanying index to financial statements and schedules in *Item 8. Financial Statements and Supplementary Data*.

All other financial statement schedules required under SEC rules that are not included in this Annual Report on Form 10-K, are omitted either because they are not applicable or the required information is contained in *Item 8. Financial Statements and Supplementary Data*.

3. Exhibits

The exhibits required to be filed pursuant to Item 15(b) of Form 10-K are listed in the Exhibit Index filed herewith, which Exhibit Index is incorporated herein by reference.

2(1)†	Agreement and Plan of Merger, dated as of October 22, 2023, among Chevron Corporation, Yankee Merger Sub Inc. and Hess Corporation.
3(1)	Restated Certificate of Incorporation of Registrant, including amendment thereto dated May 3, 2006 incorporated by reference to Exhibit 3(1) of Registrant’s Form 10-Q for the three months ended June 30, 2006.
3(2)	Certificate of Amendment to Restated Certificate of Incorporation of Registrant, dated May 22, 2013, incorporated by reference to Exhibit 3(1) of Form 8-K of Registrant filed on May 22, 2013.
3(3)	Certificate of Amendment to Restated Certificate of Incorporation of Registrant, effective May 12, 2014, incorporated by reference to Exhibit 3(1) of Form 8-K of Registrant filed on May 13, 2014.
3(4)	Certificate of Elimination of 8.00% Series A Mandatory Convertible Preferred Stock of Registrant, incorporated by reference to Exhibit 3(4) of Form 10-K of Registrant for the year ended December 31, 2019.
3(5)	By-Laws of Hess Corporation (as amended effective May 6, 2020) incorporated by reference to Exhibit 3(1) of Form 10-Q of Registrant for the three months ended March 31, 2020.
3(6)	Amendment to the By-Laws of Hess Corporation (effective as of October 22, 2023) incorporated by reference to Exhibit 3(1) of Form 8-K of Registrant filed on October 23, 2023.
4(1)	Credit Agreement, dated as of July 14, 2022, among Hess Corporation, the subsidiary party thereto, the lenders party thereto, and JPMorgan Chase Bank, N.A., as administrative agent incorporated by reference to Exhibit 10(1) of Form 8-K of the Registrant, filed on July 15, 2022.
4(2)	Indenture dated as of October 1, 1999, between Registrant and The Chase Manhattan Bank, as Trustee, incorporated by reference to Exhibit 4(1) of Form 10-Q of Registrant for the three months ended September 30, 1999.
4(3)	First Supplemental Indenture, dated as of October 1, 1999, between Registrant and The Chase Manhattan Bank, as Trustee, relating to Registrant’s 7 3/8% Notes due 2009 and 7 7/8% Notes due 2029, incorporated by reference to Exhibit 4(2) of Form 10-Q of Registrant for the three months ended September 30, 1999.
4(4)	Prospectus Supplement, dated August 8, 2001, to Prospectus dated July 27, 2001 relating to Registrant’s 5.30% Notes due 2004, 5.90% Notes due 2006, 6.65% Notes due 2011 and 7.30% Notes due 2031, incorporated by reference to Registrant’s prospectus filed pursuant to Rule 424(b)(2) under the Securities Act of 1933, as amended, on August 9, 2001.
4(5)	Prospectus Supplement, dated February 28, 2002, to Prospectus dated July 27, 2001 relating to Registrant’s 7.125% Notes due 2033, incorporated by reference to Registrant’s prospectus filed pursuant to Rule 424(b)(4) under the Securities Act of 1933, as amended, on March 1, 2002.
4(6)	Indenture dated as of March 1, 2006, between Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase Bank, N.A., as Trustee, including form of Note, incorporated by reference to Exhibit 4 to Registrant’s Form S-3ASR filed on March 1, 2006.
4(7)	Form of 6.00% Note due 2040, incorporated by reference to Exhibit 4(1) to Form 8-K of Registrant filed on December 15, 2009.
4(8)	Form of 5.60% Note due 2041, incorporated by reference to Exhibit 4(1) to Form 8-K of Registrant filed on August 12, 2010.
4(9)	Form of 3.50% Note due 2024, incorporated by reference to Exhibit 4(3) to Form 8-K of Registrant filed on June 25, 2014.
4(10)	Form of 4.30% Note due 2027, incorporated by reference to Exhibit 4(1) to Form 8-K of Registrant filed on September 28, 2016.

4(11)	Form of 5.80% Note due 2047, incorporated by reference to Exhibit 4(2) to Form 8-K of Registrant filed on September 28, 2016.
4(12)	Description of Hess Corporation's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 incorporated by reference to Exhibit 4(12) of Form 10-K of Registrant for the year ended December 31, 2019. Other instruments defining the rights of holders of long-term debt of Registrant and its consolidated subsidiaries are not being filed since the total amount of securities authorized under each such instrument does not exceed 10% of the total assets of Registrant and its subsidiaries on a consolidated basis. Registrant agrees to furnish to the Securities and Exchange Commission a copy of any instruments defining the rights of holders of long-term debt of Registrant and its subsidiaries upon request.
10(1)*	Annual Cash Incentive Plan description incorporated by reference to Item 5.02 of Form 8-K of Registrant filed on March 1, 2023.
10(2)*	Financial Counseling Program description incorporated by reference to Exhibit 10(6) of Form 10-K of Registrant for the fiscal year ended December 31, 2004.
10(3)*	Hess Corporation Savings and Stock Bonus Plan incorporated by reference to Exhibit 10(7) of Form 10-K of Registrant for the fiscal year ended December 31, 2006.
10(4)*	Letter Agreement, dated May 17, 2001, between Registrant and John P. Rielly relating to Mr. Rielly's participation in the Hess Corporation Pension Restoration Plan, incorporated by reference to Exhibit 10(18) of Form 10-K of Registrant for the fiscal year ended December 31, 2002.
10(5)*	Amended and Restated 2008 Long-term Incentive Plan, incorporated by reference to exhibit 10(1) of Form 8-K of the Registrant filed on May 12, 2015.
10(6)*	Forms of Awards under Registrant's 2008 Long-term Incentive Plan, incorporated by reference to Exhibit 10(14) of Form 10-K of Registrant for the fiscal year ended December 31, 2009.
10(7)*	Form of Amended and Restated Change in Control Termination Benefits Agreement, dated as of May 29, 2009, incorporated by reference to Exhibit 10(1) of Form 10-Q of Registrant for the three months ended June 30, 2009. A substantially identical agreement (differing only in the signatories thereto) was entered into between Registrant and John B. Hess.
10(8)*	Amended and Restated Change in Control Termination Benefits Agreement, dated as of May 29, 2009, between Registrant and John P. Rielly, incorporated by reference to Exhibit 10(17) of Form 10-K of Registrant for the fiscal year ended December 31, 2009. Substantially identical agreements (differing only in the signatories thereto) were entered into between Registrant and other executive officers (including the named executive officers, other than Barbara Lowery-Yilmaz and John B. Hess).
10(9)*	Form of Change in Control Termination Benefits Agreement, dated as of August 3, 2015, between the Registrant and Barbara Lowery-Yilmaz, incorporated by reference to Exhibit 10(2) of Form 10-Q of Registrant for the three months ended June 30, 2021. Substantially identical agreements (differing only in the signatories thereto) were entered into between the Registrant and other senior officers.
10(10)*	Agreement between Registrant and Gregory P. Hill, relating to Mr. Hill's compensation and other terms of employment, incorporated by reference to Item 5.02 of Form 8-K of Registrant filed January 7, 2009.
10(11)*	Agreement between Registrant and Timothy B. Goodell, relating to Mr. Goodell's compensation and other terms of employment, incorporated by reference to Exhibit 10(20) of Registrant's Form 10-K for the fiscal year ended December 31, 2009.
10(12)*	Deferred Compensation Plan of Registrant, dated December 1, 1999, incorporated by reference to Exhibit 10(16) of Form 10-K of Registrant for the fiscal year ended December 31, 1999.
10(13)*	Hess Corporation 2017 Long-Term Incentive Plan, incorporated by reference to Exhibit 10(1) of Form 8-K of Registrant filed on June 13, 2017.
10(14)*	Form of Restricted Stock Award Agreement under the 2017 Long-Term Incentive Plan incorporated by reference to Exhibit 10(1) of Form 10-Q of Registrant for the three months ended March 31, 2020.
10(15)*	Form of Stock Option Award Agreement under the 2017 Long-Term Incentive Plan incorporated by reference to Exhibit 10(2) of Form 10-Q of Registrant for the three months ended March 31, 2020.
10(16)*	Form of 2021 Performance Award Agreement under the 2017 Long-Term Incentive Plan incorporated by reference to Exhibit 10(1) of Form 10-Q of the Registrant, for the three months ended March 31, 2021.
10(17)*	Amendment No. 1 to the Hess Corporation 2017 Long-Term Incentive Plan incorporated by reference to Exhibit 10(1) of Form 8-K of the Registrant, filed on June 3, 2021.
10(18)*	Form of 2022 Performance Award Agreement under the 2017 Long-Term Incentive Plan incorporated by reference to Exhibit 10(1) of Form 10-Q of Registrant for the three months ended March 31, 2022.
10(19)*	Form of 2023 Performance Award Agreement under the 2017 Long-Term Incentive Plan incorporated by reference to Exhibit 10(1) of Form 10-Q of Registrant for the three months ended March 31, 2023.
10(20)	Voting and Support Agreement, dated October 22, 2023, by and among Chevron Corporation, Hess Corporation and John B. Hess incorporated by reference to Exhibit 10(1) of Form 8-K of Registrant filed on October 23, 2023.

21	Subsidiaries of Registrant.
23(1)	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm, dated February 26, 2024.
23(2)	Consent of DeGolyer and MacNaughton dated February 26, 2024.
24	Power of Attorney (included on the signatures page of this Annual Report on Form 10-K).
31(1)	Certification required by Rule 13a-14(a) (17 CFR 240.13a-14(a)) or Rule 15d-14(a) (17 CFR 240.15d-14(a)).
31(2)	Certification required by Rule 13a-14(a) (17 CFR 240.13a-14(a)) or Rule 15d-14(a) (17 CFR 240.15d-14(a)).
32(1)#	Certification required by Rule 13a-14(b) (17 CFR 240.13a-14(b)) or Rule 15d-14(b) (17 CFR 240.15d-14(b)) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
32(2)#	Certification required by Rule 13a-14(b) (17 CFR 240.13a-14(b)) or Rule 15d-14(b) (17 CFR 240.15d-14(b)) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
97*	Registrant's Compensation Recovery Policy.
99(1)	Letter report of DeGolyer and MacNaughton, Independent Petroleum Engineering Consulting Firm, dated February 7, 2024, on proved reserves audit as of December 31, 2023 of certain properties attributable to Registrant.
101(INS)	Inline XBRL Instance Document
101(SCH)	Inline XBRL Schema Document
101(CAL)	Inline XBRL Calculation Linkbase Document
101(LAB)	Inline XBRL Labels Linkbase Document
101(PRE)	Inline XBRL Presentation Linkbase Document
101(DEF)	Inline XBRL Definition Linkbase Document
104	The cover page from the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2023 has been formatted in Inline XBRL.

** These exhibits relate to executive compensation plans and arrangements.*
† Schedules have been omitted pursuant to Item 601(a)(5) of Regulation S-K.
 # Furnished herewith.

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, on the 26th day of February 2024.

By /s/ John P. Rielly

(John P. Rielly)
Executive Vice President and
Chief Financial Officer

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints John B. Hess, Timothy B. Goodell and John P. Rielly or any of them, 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 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, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and to perform each and every act and thing requisite and necessary to be done in and about the premises, as fully and to all intents and purposes as he or she might or would do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his or her substitute or 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 behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ John B. Hess **John B. Hess**	Director and Chief Executive Officer (Principal Executive Officer)	February 26, 2024
/s/ James H. Quigley **James H. Quigley**	Director and Chairman of the Board	February 26, 2024
/s/ Terrence J. Checki **Terrence J. Checki**	Director	February 26, 2024
/s/ Leonard S. Coleman Jr. **Leonard S. Coleman Jr.**	Director	February 26, 2024
/s/ Lisa Glatch **Lisa Glatch**	Director	February 26, 2024
/s/ Edith E. Holiday **Edith E. Holiday**	Director	February 26, 2024
/s/ Marc S. Lipschultz **Marc S. Lipschultz**	Director	February 26, 2024
/s/ Raymond J. McGuire **Raymond J. McGuire**	Director	February 26, 2024
/s/ David McManus **David McManus**	Director	February 26, 2024
/s/ Dr. Kevin O. Meyers **Dr. Kevin O. Meyers**	Director	February 26, 2024
/s/ Karyn F. Ovelmen **Karyn F. Ovelmen**	Director	February 26, 2024
/s/ John P. Rielly **John P. Rielly**	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 26, 2024
/s/ William G. Schrader **William G. Schrader**	Director	February 26, 2024

Exhibit 21

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUBSIDIARIES OF THE REGISTRANT

Name of Company	Registrant Ownership %	Jurisdiction
Hess Asia Holdings Inc.	100	Cayman Islands
Hess Bakken Investments II, LLC	100	Delaware
Hess Bakken Investments III, LLC	100	Delaware
Hess Bakken Investments IV, LLC	100	Delaware
Hess Bakken Processing LLC	38	Delaware
Hess Baldpate-Penn State LLC	100	Delaware
Hess Canada (Aspy) Exploration Limited	100	Cayman Islands
Hess Canada Exploration Limited	100	Cayman Islands
Hess Canada Oil and Gas ULC	100	Nova Scotia, Canada
Hess Capital Limited	100	Cayman Islands
Hess Capital Services Holdings, LLC	100	Delaware
Hess Capital Services Limited	100	Cayman Islands
Hess Capital Services LLC	100	Delaware
Hess Conger LLC	100	Delaware
Hess Energy Exploration LLC	100	Delaware
Hess Equatorial Guinea Investments Limited	100	Cayman Islands
Hess Exploration and Production Holdings LLC	100	Delaware
Hess Exploration and Production Malaysia B.V.	100	The Netherlands
Hess Exploration Services, Inc.	100	Delaware
Hess GOM Deepwater LLC	100	Delaware
Hess GOM Deepwater Sub-Holdings LLC	100	Delaware
Hess GOM Exploration LLC	100	Delaware
Hess Guyana (Block B) Exploration Limited	100	Cayman Islands
Hess Guyana Exploration Limited	100	Cayman Islands
Hess Holdings EG Limited	100	Cayman Islands
Hess Holdings GOM Ventures LLC	100	Delaware
Hess Holdings West Africa Limited	100	Cayman Islands
Hess (Indonesia-VIII) Holdings Limited	100	Cayman Islands
Hess Infrastructure Partners LP	38	Delaware
Hess International Holdings Corporation	100	Delaware
Hess International Holdings Limited	100	Cayman Islands
Hess International Receivables Limited	100	Cayman Islands
Hess International Sales LLC	100	Delaware
Hess Limited	100	England & Wales
Hess Llano LLC	100	Delaware
Hess Middle East New Ventures Limited	100	Cayman Islands
Hess Midstream Operations LP	38	Delaware
Hess Midstream Partners GP LP	38	Delaware
Hess New Ventures Exploration Limited	100	Cayman Islands
Hess North Dakota Export Logistics Holdings LLC	38	Delaware

Name of Company	Registrant Ownership %	Jurisdiction
Hess North Dakota Export Logistics LLC	38	Delaware
Hess North Dakota Export Logistics Operations LP	38	Delaware
Hess North Dakota Pipelines Holdings LLC	38	Delaware
Hess North Dakota Pipelines LLC	38	Delaware
Hess NWE Holdings	100	England & Wales
Hess Offshore Response Company, LLC	100	Delaware
Hess Ohio Developments, LLC	100	Delaware
Hess Ohio Holdings, LLC	100	Delaware
Hess Ohio Sub-Holdings LLC	100	Delaware
Hess Oil & Gas Sdn. Bhd.	100	Malaysia
Hess Oil and Gas Holdings Inc.	100	Cayman Islands
Hess Oil and Gas International Limited	100	Bermuda
Hess Oil and Gas International II Limited	100	Cayman Islands
Hess Oil Company of Thailand (JDA) Limited	100	Cayman Islands
Hess Oil Company of Thailand Ltd. Co.	100	Texas
Hess Oil Production and Exploration LLC	100	Delaware
Hess Services UK Limited	100	England & Wales
Hess Stampede LLC	100	Delaware
Hess Suriname Exploration Limited	100	Cayman Islands
Hess Tank Cars Holdings II LLC	38	Delaware
Hess Tank Cars LLC	38	Delaware
Hess Tank Cars II LLC	38	Delaware
Hess TGP Finance Company LLC	100	Delaware
Hess TGP Holdings LLC	38	Delaware
Hess TGP Operations LP	38	Delaware
Hess Tioga Gas Plant LLC	38	Delaware
Hess Trading Corporation	100	Delaware
Hess Tubular Bells LLC	100	Delaware
Hess Water Services LLC	38	Delaware
Hess West Africa Holdings Limited	100	Cayman Islands

Each of the foregoing subsidiaries conducts business under the name listed. The above list does not include 45 subsidiary holding companies (18 domestic and 27 non-U.S.) that would otherwise be reported except that they are ultimately 100% owned by the Registrant and, as their line of business, fulfill similar roles to those holding companies separately identified in the above list. In addition, we have excluded subsidiaries associated with divested assets, discontinued activities and those that when considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary.

Exhibit 23(1)

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-43569) pertaining to the Hess Corporation Employees' Savings Plan,

(2) Registration Statement (Form S-8 No. 333-150992) pertaining to the Hess Corporation Amended and Restated 2008 Long-Term Incentive Plan and the Hess Corporation 2017 Long-Term Incentive Plan,

(3) Registration Statement (Form S-8 No. 333-167076) pertaining to the Hess Corporation Amended and Restated 2008 Long-Term Incentive Plan and the Hess Corporation 2017 Long-Term Incentive Plan,

(4) Registration Statement (Form S-8 No. 333-181704) pertaining to the Hess Corporation Amended and Restated 2008 Long-Term Incentive Plan and the Hess Corporation 2017 Long-Term Incentive Plan,

(5) Registration Statement (Form S-8 No. 333-204929) pertaining to the Hess Corporation Amended and Restated 2008 Long-Term Incentive Plan and the Hess Corporation 2017 Long-Term Incentive Plan,

(6) Registration Statement (Form S-8 No. 333-219113) pertaining to the Hess Corporation 2017 Long-Term Incentive Plan,

(7) Registration Statement (Form S-8 No. 333-257070) pertaining to the Hess Corporation 2017 Long-Term Incentive Plan, and

(8) Registration Statement (Form S-3 No. 333-253681) of Hess Corporation;

of our reports dated February 26, 2024, with respect to the consolidated financial statements of Hess Corporation and the effectiveness of internal control over financial reporting of Hess Corporation included in this Annual Report (Form 10-K) of Hess Corporation for the year ended December 31, 2023.

Ernst & Young LLP

New York, New York
February 26, 2024

Exhibit 23(2)

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 26, 2024

Hess Corporation
1185 Avenue of the Americas
New York, New York 10036

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton as an independent petroleum engineering consulting firm, to references to our report of third party dated February 7, 2024, containing our opinion on the estimated proved reserves, as of December 31, 2023, attributable to certain properties in which Hess Corporation has represented it holds an interest (our "Report") under the heading "Proved Oil and Gas Reserves–Reserves Audit," and to the inclusion of our Report as an exhibit in Hess Corporation's Annual Report on Form 10-K for the year ended December 31, 2023. We also consent to all such references, including under the heading "Experts," and to the incorporation by reference of our Report in the Registration Statements filed by Hess Corporation on Form S-3 (No. 333-253681) and Form S-8 (No. 333-43569, No. 333-150992, No. 333-167076, No. 333-181704, No. 333-204929, No. 333-219113, and No. 333-257070).

Very truly yours,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31(1)

I, John B. Hess, certify that:

1. I have reviewed this annual report on Form 10-K of Hess Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By ______________________

John B. Hess
Chief Executive Officer

Date: February 26, 2024

Exhibit 31(2)

I, John P. Rielly, certify that:

1. I have reviewed this annual report on Form 10-K of Hess Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By John P. Rielly

John P. Rielly
Executive Vice President and
Chief Financial Officer

Date: February 26, 2024

Exhibit 32(1)

CERTIFICATION PURSUANT TO

18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Hess Corporation (the Corporation) on Form 10-K for the period ended December 31, 2023 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, John B. Hess, Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

By ______________________
John B. Hess
Chief Executive Officer

Date: February 26, 2024

A signed original of this written statement required by Section 906 has been provided to the Corporation and will be retained by the Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(2)

CERTIFICATION PURSUANT TO

18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Hess Corporation (the Corporation) on Form 10-K for the period ended December 31, 2023 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, John P. Rielly, Executive Vice President and Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

By /s/ John P. Rielly

John P. Rielly
Executive Vice President and
Chief Financial Officer

Date: February 26, 2024

A signed original of this written statement required by Section 906 has been provided to the Corporation and will be retained by the Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 7, 2024

Board of Directors
Hess Corporation
1185 Avenue of the Americas
New York, New York 10036

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2023, of the net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Hess Corporation (Hess) has represented it holds an interest to determine the reasonableness of Hess' estimates. This evaluation was completed on February 7, 2024. Hess has represented that these properties account for approximately 89 percent on a net equivalent barrel basis of Hess' net proved reserves, as of December 31, 2023, and that the net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4-10(a) (1)–(32) of Regulation S–X of the United States Securities and Exchange Commission (SEC). It is our opinion that the procedures and methodologies employed by Hess for the preparation of its proved reserves estimates as of December 31, 2023, comply with the current requirements of the SEC. We have reviewed information provided by Hess that it represents to be Hess' estimates of the net reserves, as of December 31, 2023, for the same properties as those which we evaluated. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Hess.

Reserves estimates included herein are expressed as net reserves as represented by Hess. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2023. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Hess after deducting all interests held by others.

Certain properties evaluated herein are subject to the terms of production sharing contracts (PSC). The terms of these PSCs generally allow for working interest participants to be reimbursed for portions of capital costs and operational expenses and to share in the profits. The reimbursements and profit proceeds are converted to a barrel of oil equivalent or standard cubic foot of gas equivalent by dividing by product prices to estimate the "entitlement quantities." These entitlement quantities are equivalent in principle to net reserves and are used to calculate an equivalent net share, termed an "entitlement interest." In this report, Hess' net reserves or interest for the properties subject to these PSCs is the entitlement based on Hess' working interest.

Estimates of reserves should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Hess. In the preparation of this report we have relied, without independent verification, upon such information furnished by Hess with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination was not considered necessary for the purposes of this report.

Definition of Reserves

Petroleum reserves estimated by Hess included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used by Hess in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any; and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10(a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019" and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Hess, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved. The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by Hess.

Hess has represented that its senior management is committed to the development plan provided by Hess and that Hess has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and original gas in place (OGIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material-balance methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP and OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors based on an analysis of reservoir performance, including production rate, reservoir pressure, and reservoir fluid properties.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production as defined under the Definition of Reserves heading of this report or the expiration of the fiscal agreement, as appropriate.

In certain cases, reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Hess from wells drilled through December 1, 2023, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available for most properties only through August 2023. Estimated cumulative production, as of December 31, 2023, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for 4 months.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C5+) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in millions of barrels (106bbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as marketable gas and fuel gas. Marketable gas is defined as the total gas produced from the reservoir after reduction for shrinkage resulting from field separation; processing, including removal of the nonhydrocarbon gas to meet pipeline specifications; and flare and other losses but not from fuel usage. Fuel gas defined as that portion of the gas consumed in field operations. Gas reserves estimated herein are reported as marketable gas reserves; therefore, fuel gas is included as reserves. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.7 pounds per square inch absolute (psia). Gas quantities included in this report are expressed in billions of cubic feet (10^9ft^3).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas includes both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

At the request of Hess, marketable gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

Primary Economic Assumptions

This report has been prepared using initial prices, expenses, and costs provided by Hess in United States dollars (U.S.$). Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the reserves reported herein:

Oil and Condensate Prices

Hess has represented that the oil and condensate prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The 12-month average reference prices used were U.S.$78.10 per barrel for West Texas Intermediate and U.S. $82.51 per barrel for Brent. Hess supplied differentials by field to the relevant reference prices and the prices were held constant thereafter. The volume-weighted average price attributable to the estimated proved reserves over the lives of the independently evaluated properties was U.S.$77.03 per barrel of oil and condensate.

NGL Prices

Hess has represented that the NGL prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The volume-weighted average price attributable to the estimated proved reserves over the lives of the independently evaluated properties was U.S.$20.99 per barrel of NGL.

Gas Prices

Hess has represented that gas prices were based on reference prices, calculated as the unweighted arithmetic average of the first-day-of- the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The 12-month average reference price for NYMEX was U.S.$2.75 per million Btu. The gas prices were adjusted for each property using differentials to the NYMEX reference price furnished by Hess and held constant thereafter. The volume-weighted average price attributable to the estimated proved reserves over the lives of the independently evaluated properties was U.S.$2.78 per thousand cubic feet of gas.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Hess and based on existing economic conditions, were held constant for the lives of the properties. Future capital expenditures were estimated using 2023 values, provided by Hess, and were not adjusted for inflation. In certain cases, future expenditures, either higher or lower than current expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Hess for all properties and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the undeveloped reserves.

In our opinion, the information relating to estimated proved reserves of oil, condensate, NGL, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, and 932 235-50-9 of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the FASB and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the SEC; provided, however, that estimates of proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

DeGolyer and MacNaughton has performed an independent evaluation of the extent of the estimated net proved oil, condensate, NGL, and gas reserves of certain properties in which Hess has represented it holds an interest. Hess has represented that its estimated net proved reserves attributable to the evaluated properties were based on the definition of proved reserves of the SEC. Hess' estimates of the net proved reserves, as of December 31, 2023, attributable to these properties, which represent approximately 89 percent of Hess' reserves on a net equivalent basis, are summarized as follows, expressed in millions of barrels (106bbl), billions of cubic feet (109ft3), and millions of barrels of oil equivalent (106boe):

	Estimated by Hess Net Proved Reserves as of December 31, 2023			
	Oil and Condensate (10^6bbl)	NGL (10^6bbl)	Marketable Gas (10^9ft^3)	Oil Equivalent (10^6boe)
United States	462	261	971	885
Guyana	258	0	143	282
Malaysia and JDA	3	0	315	56
Total	**723**	**261**	**1,429**	**1,223**

1. Marketable gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.
2. Net proved fuel gas reserves included as a portion of marketable gas reserves were estimated to be 169 10^9ft^3.
3. Joint Development Area is abbreviated JDA.

In comparing the detailed net proved reserves estimates by field prepared by DeGolyer and MacNaughton and by Hess, differences have been found, both positive and negative, resulting in an aggregate difference of approximately 1.3 percent when compared on the basis of net equivalent barrels. It is DeGolyer and MacNaughton's opinion that the total net proved reserves estimates prepared by Hess, as of December 31, 2023, on the properties evaluated and referred to above, when compared on the basis of net equivalent barrels, do not differ materially from those prepared by DeGolyer and MacNaughton.

Hess' oil and gas reserves were estimated assuming the continuation of the current regulatory environment. Changes in the regulatory environment by host governments may affect the operating environment and oil and gas reserves estimates of industry participants. Such regulatory changes could include increased mandatory government participation in producing contracts, changes in royalty terms, cancellation or amendment of contract rights, or expropriation or nationalization of property. While the oil and gas industry is subject to regulatory changes that could affect an industry participant's ability to recover its reserves, neither we nor Hess are aware of any such governmental actions which restrict the recovery of the December 31, 2023, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Hess. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Hess. DeGolyer and MacNaughton has used all data, procedures, assumptions, and methods that it considers necessary to prepare this report.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

STATE OF TEXAS
FEDERICO DORDONI
128717
LICENSED
PROFESSIONAL ENGINEER

Federico Dordoni

Federico Dordoni, P.E.
Executive Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Federico Dordoni, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am an Executive Vice President with DeGolyer and MacNaughton, which firm did prepare the report of third party addressed to Hess dated February 7, 2024, and that I, as Executive Vice President, was responsible for the preparation of this report of third party.
2. That I attended Buenos Aires Institute of Technology (ITBA) University, and that I graduated with a degree in Petroleum Engineering in the year 2004; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 19 years of experience in oil and gas reservoir studies and reserves evaluations.

STATE OF TEXAS
FEDERICO DORDONI
128717
LICENSED
PROFESSIONAL ENGINEER

Federico Dordoni

Federico Dordoni, P.E.
Executive Vice President
DeGolyer and MacNaughton