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, 2019

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 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 $16,996,000,000, computed using the outstanding Common Stock and closing market price on June 28, 2019, the last business day of the Registrant's most recently completed second fiscal quarter.

At January 31, 2020, there were 305,214,587 shares of Common Stock outstanding.

Part III is incorporated by reference from the Proxy Statement for the 2020 annual meeting of stockholders.

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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; and future economic and market conditions in the oil and gas industry.

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 generally;
- potential failures or delays in increasing oil and gas reserves, including as a result of unsuccessful exploration activity, drilling risks and unforeseen reservoir conditions;
- potential failures or delays in achieving expected production levels given inherent uncertainties in estimating quantities of proved reserves;
- potential disruption or interruption of our operations due to catastrophic events, such as accidents, severe weather, geological events, shortages of skilled labor or cyber-attacks;
- reduced demand for our products, including the impact of competing or alternative energy products and political conditions and events, such as instability, changes in governments, armed conflict, economic sanctions and outbreaks of infectious diseases;
- 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 well fracking bans;
- the ability of our contractual counterparties to satisfy their obligations to us, including the operation of joint ventures under which we may not control;
- 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 weakness in the oil and gas industry or negative outcomes within commodity and financial markets;
- liability resulting from litigation, including heightened risks associated with being a general partner of Hess Midstream LP; 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:

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.

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.

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.

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.

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.

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.

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.

LIBOR – The London Interbank Offered Rate.

Mcf – One thousand cubic feet of natural gas.

Mmcfd – One thousand mcf of natural gas per day.

Net acreage or Net wells – The sum of the fractional working interests owned by us 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.

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.

Plug and perf completion – A well completion technique which involves creating perforations in the well casing that penetrate the hydrocarbon reservoir section between set plugs.

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.

Unproved properties – Properties with no proved reserves.

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.

Items 1 and 2. Business and Properties

Hess Corporation, incorporated in the State of Delaware in 1920, is a global Exploration and Production (E&P) company engaged in exploration, development, production, transportation, purchase and sale of crude oil, NGL, and natural gas with production operations and development activities located primarily in the United States (U.S.), Guyana, the Malaysia/Thailand Joint Development Area (JDA), Malaysia and Denmark. We conduct exploration activities primarily offshore Guyana, the U.S. Gulf of Mexico, and offshore Suriname and Canada. At the Stabroek Block (Hess 30%), offshore Guyana, we have announced sixteen significant discoveries. The Liza Phase 1 development achieved first production in December 2019, with peak production expected to reach up to 120,000 gross bopd. The Liza Phase 2 development was sanctioned in the second quarter of 2019 and is expected to start up by mid-2022 with production reaching up to 220,000 gross bopd. The discovered resources to date on the Stabroek Block are expected to underpin the potential for at least five FPSOs producing more than 750,000 gross bopd by 2025.

Our Midstream operating segment, which is comprised of Hess Corporation's 47% consolidated ownership interest in Hess Midstream LP at December 31, 2019, 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.

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, 2019 were $55.73 per barrel for West Texas Intermediate (WTI) (2018: $65.55) and $62.54 per barrel for Brent (2018: $72.08). Our total proved developed and undeveloped reserves at December 31 were as follows:

	Crude Oil & Condensate		Natural Gas Liquids		Natural Gas		Total Barrels of Oil Equivalent (BOE)	
	2019	2018	2019	2018	2019	2018	2019	2018
	(Millions of bbls)		(Millions of bbls)		(Millions of mcf)		(Millions of bbls)	
Developed								
United States	**293**	266	**90**	85	**400**	432	**450**	423
Europe	**32**	38	**—**	—	**65**	77	**43**	51
Africa	**107**	111	**—**	—	**118**	115	**127**	130
Asia and other (a)	**36**	4	**—**	—	**500**	585	**119**	102
	468	419	**90**	85	**1,083**	1,209	**739**	706
Undeveloped								
United States	**215**	235	**79**	90	**300**	381	**344**	389
Europe	**8**	1	**—**	—	**16**	1	**11**	1
Africa	**14**	15	**—**	—	**2**	13	**14**	17
Asia and other (a)	**57**	44	**—**	—	**192**	211	**89**	79
	294	295	**79**	90	**510**	606	**458**	486
Total								
United States	**508**	501	**169**	175	**700**	813	**794**	812
Europe	**40**	39	**—**	—	**81**	78	**54**	52
Africa	**121**	126	**—**	—	**120**	128	**141**	147
Asia and other (a)	**93**	48	**—**	—	**692**	796	**208**	181
	762	714	**169**	175	**1,593**	1,815	**1,197**	1,192

(a) Asia and other includes Guyana proved developed reserves of 31 million boe and proved undeveloped reserves of 56 million boe at December 31, 2019 (December 31, 2018: proved developed - 0 million boe; proved undeveloped - 42 million boe).

Proved undeveloped reserves were 38% of our total proved reserves at December 31, 2019 on a boe basis (2018: 41%). Proved reserves held under production sharing contracts totaled 12% of our crude oil reserves and 43% of our natural gas reserves at December 31, 2019 (2018: 7% and 44%, 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 90 through 98.

Production

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

	2019	2018	2017
Crude oil – Thousands of barrels			
United States			
Bakken	**34,090**	27,663	24,439
Other Onshore (a)	**209**	389	2,053
Total Onshore	**34,299**	28,052	26,492
Offshore	**16,628**	15,026	14,411
Total United States	**50,927**	43,078	40,903
Europe			
Denmark	**2,167**	2,231	2,988
Norway (a)	—	—	7,236
	2,167	2,231	10,224
Africa			
Libya	**6,994**	6,654	3,542
Equatorial Guinea (a)	—	—	9,201
	6,994	6,654	12,743
Asia and Other			
JDA	**555**	546	586
Malaysia	**924**	851	289
Guyana	**67**	—	—
	1,546	1,397	875
Total	**61,634**	53,360	64,745
Natural gas liquids – Thousands of barrels			
United States			
Bakken	**14,828**	10,767	10,107
Other Onshore (a)	**322**	1,647	2,972
Total Onshore	**15,150**	12,414	13,079
Offshore	**1,942**	1,703	1,733
Total United States	**17,092**	14,117	14,812
Europe - Norway (a)	—	—	340
Total	**17,092**	14,117	15,152
Natural gas – Thousands of mcf			
United States			
Bakken	**38,993**	25,625	22,621
Other Onshore (a)	**1,229**	16,167	33,478
Total Onshore	**40,222**	41,792	56,099
Offshore	**33,212**	24,452	20,987
Total United States	**73,434**	66,244	77,086
Europe			
Denmark	**2,500**	2,958	5,124
Norway (a)	**—**	**—**	6,739
	2,500	2,958	11,863
Asia and Other			
JDA	**66,127**	68,477	73,444
Malaysia (b)	**61,944**	59,995	27,225
Libya	**4,644**	4,288	—
	132,715	132,760	100,669
Total	**208,649**	201,962	189,618
Total Barrels of Oil Equivalent (in millions) (a) (b)	**114**	101	112

(a) In August 2018, the Corporation sold its joint venture interests in the Utica shale play, onshore U.S. Utica net production was 3.3 million boe for calendar year 2018 (2017: 6.9 million boe). In 2017, the Corporation sold its assets in Equatorial Guinea (November), Norway (December), and the Permian, onshore U.S. (August). Permian produced 1.5 million boe for calendar year 2017.

(b) Includes 7,122 thousand mcf of net production for 2019 (2018: 6,442 thousand mcf; 2017: 4,256 thousand mcf) from Block PM301, which is unitized into Block A-18 of the JDA.

E&P Operations

At December 31, 2019, our significant E&P assets included the following:

United States

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

Onshore:

Bakken: At December 31, 2019, we held approximately 534,000 operated net acres in the Bakken with varying working interest percentages. Net production averaged 152,000 boepd in 2019. During the year, we operated six rigs, drilled 160 wells and brought 156 wells on production, bringing the total operated production wells to 1,575 by year-end. Effective 2019, all new production wells use plug and perf completions. We were able to reduce the average cost of a plug and perf well in 2019 to $6.8 million per well from $7.6 million in 2018.

During 2020, we plan to operate six rigs, drill approximately 170 wells and bring approximately 175 wells on production. We forecast net production to average approximately 180,000 boepd in 2020 and to reach approximately 200,000 boepd by the end of 2020. In the third quarter of 2020, the Tioga Gas Plant will be shut down for approximately 45 days for a planned turnaround and tie-in of the plant expansion project which will increase gas processing capacity to 400 million cubic feet per day from 250 million cubic feet per day and is expected to be in service by mid-2021. The shutdown for the turnaround is expected to reduce 2020 average net production, mostly natural gas liquids and natural gas, by approximately 6,000 boepd. Commencing in 2021, we plan to reduce our rig count to four operated rigs and, at this level of activity, expect to hold net production relatively flat at approximately 200,000 boepd for at least five years.

Offshore:

Gulf of Mexico: At December 31, 2019, we held approximately 73,000 net developed acres, with our production operations principally at the Baldpate (Hess 50%), Conger (Hess 38%), Hack Wilson (Hess 25%), Llano (Hess 50%), Penn State (Hess 50%), Shenzi (Hess 28%), Stampede (Hess 25%) and Tubular Bells (Hess 57%) fields. At December 31, 2019, we held approximately 344,000 net undeveloped acres, of which leases covering approximately 81,000 acres are due to expire in the next three years.

In 2019, the Corporation announced a discovery at the Hess operated Esox-1 exploration well in Mississippi Canyon Block No. 726 (Hess 57%). First production from the well was achieved in February 2020 as a tie-back to the Tubular Bells production facilities. In 2020, we expect to drill up to two exploration wells in the Gulf of Mexico.

Guyana

Stabroek Block: The Stabroek Block (Hess 30%), offshore Guyana, covers approximately 6.6 million acres, which is equivalent to approximately 1,150 Gulf of Mexico blocks. The operator, Esso Exploration and Production Guyana Limited, has made sixteen significant discoveries since 2015. The discovered resources to date on the Stabroek Block are expected to underpin the potential for at least five FPSOs producing more than 750,000 gross bopd by 2025.

Under the terms of our agreement with the government, the contractors (collectively affiliates of ExxonMobil – 45%, Hess – 30%, and CNOOC – 25%) are generally entitled to recover contract costs for exploration, development and production activities within the Stabroek Block (Cost Recovery) in an amount up to 75% of gross production in any month, with any excess Cost Recovery carried over to future periods. All production not allocated to Cost Recovery in a given month (profit oil) is further allocated 50% to the government and 50% to the contractors. The contractors must also pay a royalty of 2% based on gross production, either in cash or in-kind, at the election of the government. Our resulting entitlement is 30% of the contractors' share of production.

The Liza Phase 1 development, which was sanctioned in 2017, began producing oil in December 2019 from the Liza Destiny FPSO. Production is expected to ramp up to the full capacity of 120,000 gross bopd in 2020. We forecast net production for 2020 to average approximately 25,000 bopd.

The Liza Phase 2 development was sanctioned in 2019 and will utilize the Liza Unity FPSO to produce up to 220,000 gross bopd, with first production expected by early 2022. Six drill centers are planned with a total of 30 wells, including 15 production wells, nine water injection wells and six gas injection wells. In 2020, the operator plans to commence development drilling, installation of subsea flow lines and equipment, and installation of topside facilities modules on the Liza Unity FPSO.

A third development, at the Payara Field, is expected to be sanctioned following government and regulatory approvals and is expected to produce up to 220,000 gross bopd with startup as early as 2023. In addition to the first three developments, planning is underway for additional FPSOs. The ultimate sizing and timing of these potential developments will be a function of further exploration and appraisal drilling.

The operator is currently utilizing four drillships for exploration, appraisal and development drilling activities, and intends to bring in a fifth drillship in 2020.

In 2019, the following exploration and appraisal wells were drilled on the Stabroek Block (in chronological order):

Tilapia: The Tilapia-1 well encountered approximately 305 feet of high-quality, oil-bearing sandstone reservoir and is located approximately 3.4 miles west of the Longtail-1 well.

Haimara: The Haimara-1 well encountered approximately 207 feet of high-quality, gas condensate bearing sandstone reservoir and is located approximately 19 miles east of the Pluma-1 well.

Yellowtail: The Yellowtail-1 well encountered approximately 292 feet of high-quality oil-bearing sandstone reservoir and is located approximately 6 miles northwest of the Tilapia discovery.

Hammerhead: The Hammerhead-2 well, located approximately 0.9 miles from the Hammerhead-1 discovery well, and the Hammerhead-3 well, located approximately 1.9 miles from Hammerhead-1, were both successfully drilled and encountered high quality, oil-bearing sandstone reservoir. A drill stem test was also performed on Hammerhead-3. Results are under evaluation.

Tripletail: The Tripletail-1 well encountered approximately 108 feet of high-quality oil-bearing sandstone reservoir and is located approximately 3 miles northeast of the Longtail discovery. Additional oil-bearing reservoirs were subsequently encountered below the previously announced Tripletail discovery, which are still under evaluation.

Ranger: The Ranger-2 appraisal well was completed, and a drill stem test was performed. Results are under evaluation.

Mako: The Mako-1 well encountered approximately 164 feet of high-quality oil-bearing sandstone reservoir and is located approximately 6 miles southeast of the Liza Field.

In January 2020, the operator announced the sixteenth discovery on the Stabroek Block at the Uaru-1 well. The Uaru-1 well encountered approximately 94 feet of high-quality oil-bearing sandstone reservoir and is located approximately 10 miles northeast of the Liza Field. The operator's plans for 2020 exploration and appraisal drilling activities include focusing the first half of the year primarily on appraisal of discoveries in the greater Turbot area, and the second half of the year to include the drilling of several exploration wells, which is expected to include further tests of emerging deeper plays on the Stabroek Block.

Kaieteur Block: In 2018, we acquired a participating interest in the Kaieteur Block (Hess 15%), which is adjacent to the Stabroek Block. The operator, Esso Exploration and Production Guyana Limited, completed a 2D seismic shoot in 2019 and expects to drill the Tanager-1 exploration well in 2020.

Asia

Malaysia/Thailand Joint Development Area (JDA): Production comes from the Carigali Hess operated offshore Block A-18 in the Gulf of Thailand (Hess 50%). A multi-year drilling program is planned to commence in the fourth quarter of 2020.

Malaysia: Our production in Malaysia comes from our interest in Block PM301 (Hess 50%), which is adjacent to and is unitized with Block A-18 of the JDA and Block PM302 (Hess 50%) located in the North Malay Basin (NMB), offshore Peninsular Malaysia. In 2020, we plan to continue drilling and development activities.

Europe

Denmark: Production comes from our operated interest in the South Arne Field (Hess 62%). In 2019, at the Hess operated License 6/16 (Hess 80%), the Corporation drilled the Jill-1 exploration commitment well, which did not encounter commercial quantities of hydrocarbons.

Africa

Libya: At the onshore Waha concession in Libya, which includes the Defa, Faregh, Gialo, North Gialo and Belhedan fields (Hess 8%), net production averaged approximately 21,000 boepd in 2019 (2018: 20,000 boepd; 2017: 10,000 boepd). In January 2020, the Libyan National Oil Company declared force majeure after oil exports were ceased at five oil export terminals. The Company's net investment in Libya was approximately $100 million at December 31, 2019.

Other Non-Producing Countries

Suriname: We hold a 33% non-operated participating interest in Block 42, offshore Suriname. In 2021, the operator, Kosmos Energy Ltd., plans to drill an exploration well. We also hold a 33% non-operated participating interest in Block 59, offshore Suriname, where the operator, ExxonMobil Exploration and Production Suriname B.V., is conducting a seismic program.

Canada: We hold a 50% non-operated participating interest in four exploration licenses offshore Nova Scotia and a 25% non-operated participating interest in three exploration licenses offshore Newfoundland. In 2022, the operator BP Canada plans to drill one exploration well in Newfoundland.

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 80 billion cubic feet of natural gas per year through 2025 and approximately 40 billion cubic feet per year in 2026 and 2027. At the North Malay Basin development project offshore Peninsular Malaysia, we have annual net sales commitments of approximately 55 billion cubic feet per year through 2024. Our estimated total volume of production subject to these sales commitments is approximately 835 billion cubic feet of natural gas. We also have multiple minimum delivery commitments in the Bakken for natural gas and NGL with various end dates up 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:

	2019	2018	2017
Average selling prices (a)			
Crude oil – per barrel (including hedging)			
United States			
Onshore	**$ 53.19**	$ 56.90	$ 46.04
Offshore	**59.18**	62.02	47.34
Total United States	**55.15**	58.69	46.50
Europe	**66.29**	70.08	55.03
Africa	**64.91**	69.64	53.17
Asia	**61.81**	70.42	56.99
Worldwide	**56.77**	60.77	49.23
Crude oil – per barrel (excluding hedging)			
United States			
Onshore	**$ 53.18**	$ 60.64	$ 46.76
Offshore	**59.17**	65.73	48.15
Total United States	**55.14**	62.41	47.25
Europe	**66.29**	70.08	55.14
Africa	**64.91**	69.64	53.25
Asia	**61.81**	70.42	56.99
Worldwide	**56.76**	63.80	49.75
Natural gas liquids – per barrel			
United States			
Onshore	**$ 13.20**	$ 21.29	$ 17.67
Offshore	**13.31**	25.58	21.34
Total United States	**13.21**	21.81	18.10
Europe	**—**	—	29.04
Worldwide	**13.21**	21.81	18.35
Natural gas – per mcf			
United States			
Onshore	**$ 1.59**	$ 2.29	$ 1.96
Offshore	**2.12**	2.68	2.22
Total United States	**1.83**	2.43	2.03
Europe	**3.81**	3.61	4.42
Asia and other	**5.04**	5.07	4.27
Worldwide	**3.90**	4.18	3.37
Average production (lifting) costs per barrel of oil equivalent produced (b)			
United States			
Onshore (c)	**$ 20.42**	$ 22.34	$ 19.64
Offshore	**11.27**	13.80	11.89
Total United States	**17.66**	19.74	17.42
Europe	**26.35**	26.23	21.95
Africa	**4.22**	4.42	14.40
Asia and other	**7.70**	6.16	7.83
Worldwide	**14.93**	15.73	16.07

(a) Includes inter-company transfers valued at approximate market prices, primarily onshore U.S., which include certain processing and distribution fees.
(b) 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.
(c) Includes Midstream tariff expense of $12.89 per boe in 2019 (2018: $13.69 per boe; 2017: $11.10 per boe).

Gross and Net Undeveloped Acreage

At December 31, 2019, gross and net undeveloped acreage amounted to:

	Undeveloped Acreage (a)	
	Gross	Net
	(In thousands)	
United States	389	362
South America	14,236	3,915
Europe	94	68
Africa	3,334	272
Asia and other (b)	6,350	2,755
Total (c)	24,403	7,372

(a) Includes acreage held under production sharing contracts.
(b) Includes 5.1 million gross acres (2.1 million net acres) offshore Canada.
(c) At December 31, 2019, 58% of our net undeveloped acreage, primarily offshore Canada and Suriname, 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, 2019 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	1,008	591	2,897	1,336	15	7
South America	95	29	5	2	—	—
Europe	23	14	19	12	—	—
Africa	9,564	782	1,125	92	10	1
Asia and other	452	226	—	—	128	62
Total	11,142	1,642	4,046	1,442	153	70

(a) Includes multiple completion wells (wells producing from different formations in the same bore hole) totaling 112 gross wells and 65 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		
	2019	2018	2017	2019	2018	2017
Productive wells						
United States	**—**	—	—	**140**	92	65
South America	**2**	2	2	**2**	—	—
Europe	**—**	—	—	**—**	—	1
Africa	**—**	—	—	**2**	—	—
Asia and other	**—**	2	—	**3**	1	1
	2	4	2	**147**	93	67
Dry holes						
United States	**—**	—	—	**—**	—	—
Europe	**1**	—	—	**—**	—	—
Africa (a)	**—**	—	—	**—**	—	—
Asia and other	**—**	2	—	**—**	—	—
	1	2	—	**—**	—	—
Total	**3**	6	2	**147**	93	67

(a) In 2017, we expensed seven wells in our Deepwater Tano/Cape Three Points Block, offshore Ghana, which were drilled in prior years.

Number of Wells in the Process of Being Drilled

At December 31, 2019, the number of wells in the process of drilling amounted to:

	Gross Wells	Net Wells
United States	194	54
South America	2	1
Asia and other	4	2
Total	200	57

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 March 1, 2019, HIP acquired Hess’s existing Bakken water services business for $225 million in cash. As a result of this transaction between entities under common control, we recorded an after-tax gain of $78 million in additional paid-in capital with an offsetting reduction to noncontrolling interest to reflect the adjustment to GIP’s noncontrolling interest in HIP. On March 22, 2019, HIP and Hess Midstream Partners acquired crude oil and gas gathering assets, and HIP acquired water gathering assets of Summit Midstream Partners LP’s Tioga Gathering System for aggregate cash consideration of approximately $90 million, with the potential for an additional $10 million of contingent payments in future periods subject to certain future performance metrics. On January 25, 2018, Hess Midstream Partners entered into a 50/50 joint venture with Targa Resources Corp. to construct a new 200 million standard cubic feet per day gas processing plant call Little Missouri 4. The plant, which is operated by Targa, was placed into service in the third quarter of 2019.

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 LP. 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, we 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 own 6% of the consolidated entity on an as-exchanged basis and Hess and GIP each own 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, or referred to as “Hess Corporation’s 47% consolidated ownership interest in Hess Midstream LP”.

At December 31, 2019, 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 1,350 miles of high and low pressure natural gas and NGL gathering pipelines with a current capacity of up to approximately 450 mmcfd, including an aggregate compression capacity of approximately 240 mmcfd. The system also includes the Hawkeye Gas Facility, which contributes approximately 50 mmcfd of the system’s current compression capacity.

- *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 550 miles of crude oil gathering pipelines with a current capacity of up to approximately 240,000 bopd. The system also includes the Hawkeye Oil Facility, which contributes approximately 75,000 bopd of the system's current capacity.

- *Tioga Gas Plant:* A natural gas processing and fractionation plant located in Tioga, North Dakota, with a current processing capacity of approximately 250 mmcfd and fractionation capacity of approximately 60,000 boepd. In 2019, Hess Midstream LP announced plans to expand processing capacity at the plant by 150 mmcfd for total processing capacity of 400 mmcfd. Capital expenditures for the expansion are expected to be $150 million and the expansion is expected to be in service by mid-2021. The Tioga Gas Plant is expected to commence a shut down in the third quarter of 2020 for approximately 45 days for a planned turnaround and tie-in of the plant expansion project.

- *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 the third quarter of 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 and to multiple 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 we operate 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 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 250 miles of pipeline in gathering systems or by third-party trucking to water handling facilities for disposal. We also transport produced water to twelve water handling and disposal facilities operated by third parties that have a combined permitted disposal capacity of 170,000 barrels per day. In 2019, we completed construction of two water handling and disposal facilities with a disposal capacity of 20,000 barrels per day.

Competition and Market Conditions

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

Other Items

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 Clean Gulf Associates (CGA), Marine Spill Response Corporation (MSRC), Marine Well Containment Company (MWCC), Wild Well Control (WWC) and Oil Spill Response Limited (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, 9 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 Committees of CGA and MSRC, as well as the Board of Directors of 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 Atlantic Named 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 $400 million of coverage is provided through an industry mutual insurance group. Above this $400 million threshold, insurance is carried which ranges in value up to $1.31 billion in total, 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 $1.08 billion, which coverage under a standard joint operating arrangement 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 joint operating agreement (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.

Environmental

Compliance with various existing environmental and pollution control regulations imposed by federal, state, local and foreign governments is not expected to have a material adverse effect on our financial condition or results of operations but 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. We spent approximately $20 million in 2019 for environmental remediation. The level of other expenditures 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. For further discussion of environmental matters see *Environment, Health and Safety* in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Information about our Executive Officers

The following table presents information as of February 20, 2020 regarding executive officers of the Corporation:

Name	Age	Office Held* and Business Experience	Year Individual Became an Executive Officer
John B. Hess	65	*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 40 years of experience in the oil and gas industry.	1983
Gregory P. Hill	58	*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	62	*Senior Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer* Mr. Goodell has been the Senior Vice President and General Counsel of the Corporation since 2009, Corporate Secretary since 2016 and Chief Compliance Officer since 2017. 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	57	*Senior Vice President and Chief Financial Officer* Mr. Rielly has been the Senior Vice President and Chief Financial Officer of the Corporation since 2004. 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	62	*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	54	*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

Name	Age	Office Held* and Business Experience	Year Individual Became an Executive Officer
Andrew Slentz	58	*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 25 years in human resources experience at large international public companies.	2016
Michael R. Turner	60	*Senior Vice President* Mr. Turner has been Senior Vice President of the Corporation since January 2020. He previously served as Senior Vice President, Global Production from January 2017 until December 2019 and Senior Vice President, Onshore from June 2009 to December 2016. Prior to joining the Corporation in 2009, Mr. Turner spent 28 years with Royal Dutch Shell and its affiliates in a variety of production leadership positions around the world. Mr. Turner will retire from the Corporation effective April 3, 2020.	2014
Barbara Lowery-Yilmaz	63	*Senior Vice President, Exploration* Ms. Lowery-Yilmaz has been the Senior Vice President, Exploration of the Corporation since August 2014. 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 the By-laws until the first meeting of directors in connection with the annual meeting of stockholders of the Registrant and until their successors shall have been duly chosen and qualified. Each of said officers was elected to the office opposite their name on June 4, 2019 except Mr. Schoonman who was elected effective January 1, 2020.*

Except for Mr. Slentz, 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. Prior to joining the Corporation, Mr. Slentz served in senior executive positions in human resources at Peabody Energy and its affiliates.

Number of Employees

At December 31, 2019, we had 1,775 employees.

Website 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 is not 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 that our Chief Executive Officer is unaware of any violation of 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.

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 instability, changes in governments, armed conflict, economic sanctions and outbreaks of infectious diseases) 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 and availability of alternative fuels or other forms of energy, the effect of energy conservation and environmental protection efforts and overall economic conditions globally. 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 2019 were $57.04 per barrel for WTI (2018: $64.90; 2017: $50.85) and $64.16 per barrel for Brent (2018: $71.69; 2017: $54.74). 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.

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, prevailing oil and gas prices, production sharing contracts, which may decrease reserves as crude oil and natural gas prices increase, and other factors. Crude oil prices declined in 2019, relative to 2018, resulting in reductions to our reported proved reserves. In contrast, crude oil prices improved in 2017 and 2018, relative to preceding years, resulting in increases to our reported proved reserves. If crude oil prices in 2020 average below prices used to determine proved reserves at December 31, 2019, it could have an adverse effect on our estimates of proved reserve volumes and on the value of our business. See *Crude Oil and Natural Gas Reserves* in *Critical Accounting Policies and Estimates* in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.*

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, fires, explosions, blowouts, cratering, pipeline interruptions and ruptures, hurricanes, severe weather, geological events, shortages in availability of skilled labor or cyber-attacks. We maintain insurance coverage against many, but not all, potential losses and liabilities in amounts we deem prudent, including for property and casualty losses. There can be no assurance that such insurance will adequately protect us against liability from all potential consequences and damages. Moreover, some forms of insurance may be unavailable in the future or be available only on terms that are deemed economically unacceptable.

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. In either case, the value of our investment may be adversely affected.

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 relating to tax increases and retroactive tax claims, disallowance of tax credits and deductions; 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; reduction of sulfur content in bunker fuel; the imposition of tariffs, limitations on access to exploration and development opportunities; prohibition on hydraulic fracturing of wells; and anti-bribery or anti-corruption laws, may adversely affect our operations and those of our counterparties with whom we have contracted, which may affect our financial results.

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. Two of the 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, 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. Any inability to access capital markets could adversely impact our financial adaptability and our ability to execute our strategy and may also expose us to heightened exposure to credit risk. In addition, borrowings on credit facilities may use LIBOR as a benchmark for establishing the rate. LIBOR is the subject of recent national, international and other regulatory guidance and proposals for reform. These reforms and other pressures may cause LIBOR to be discontinued or to perform differently than in the past. The consequences of these developments cannot be entirely predicted, but could include fluctuations in interest rates or an increase in the cost of credit facility borrowings.

Political instability in areas where we operate can adversely affect our business. Some of the international areas in which we operate are politically less stable than other areas and may be subject to civil unrest, conflict, insurgency, corruption, security risks and labor unrest. Political instability and civil unrest in North Africa, South America and the Middle East has affected and may continue to affect our interests in these areas as well as oil and gas markets generally. 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. Political instability exposes 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 threat of terrorism around the world also poses additional risks to our operations and the operations of the oil and gas industry in general.

Our oil and gas operations are subject to environmental risks and environmental 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 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 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 and sustainability 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 greenhouse gas 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 greenhouse gases from our operations, which may result in substantial capital expenditures and compliance, operating, maintenance and remediation costs. In addition, our production is sold to third parties that produce petroleum fuels, which through normal end user consumption result in the emission of greenhouse gases. 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 these 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 greenhouse gas emissions reduction requirements could severely and adversely impact the oil and gas industry and therefore significantly reduce the value of our business. 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. Furthermore, 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, in 2017 certain municipalities and private associations in California, Rhode Island, and Maryland separately filed lawsuits against over 30 fossil fuel producers, including us, for alleged damages purportedly caused by climate change.

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. 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.

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, availability of necessary personnel, construction delays, unfavorable weather conditions, equipment failures, and outbreaks of infectious diseases. These delays could impact our future results of operations and cash flows.

Departures of key members from our senior management team, and/or 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 depends upon the continued service of key members of our senior management team, who play an important role in developing and implementing our strategy. The departure of key members of senior management or an inability to recruit and retain adequate numbers of experienced technical and professional personnel in the necessary locations may prevent us from executing our strategy in full or, in part, which could negatively impact our business.

We are dependent on oilfield service companies for items including drilling rigs, equipment, supplies and skilled labor. An inability or significant delay in securing these services, or a high cost thereof, may result in material negative economic consequences. 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. 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.

We engage in risk management transactions designed to mitigate commodity price volatility and other risks but such activities 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.

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 shareholders. Moreover, these increased duties may lead to an increase in compliance costs.

Disruption, failure or cyber security breaches affecting or targeting computer, telecommunications systems, 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 use these systems to analyze and store financial and operating data and to communicate within our corporation and with outside business partners. Technical system flaws, power loss, cyber security risks, including cyber or phishing-attacks, unauthorized access, malicious software, data privacy breaches by employees or others with authorized access, ransomware, and other cyber security issues could compromise our computer and telecommunications systems or those of our business partners and result in disruptions to our business operations or the access, disclosure or loss of our data and proprietary information. 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, 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 networks and 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 and such attacks could have an adverse impact on our business and operations, including damage to our reputation and competitiveness, remediation costs, litigation or regulatory actions. In addition, as technologies evolve and these cyber security attacks become more sophisticated, we may incur significant costs to upgrade or enhance our security measures to protect against such attacks and we may face difficulties in fully anticipating or implementing adequate preventive measures or mitigating potential harm.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

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 methyl tertiary butyl ether (MTBE) in gasoline. A series of similar lawsuits, many involving water utilities or governmental entities, were filed in jurisdictions across the U.S. 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 three remaining active cases, filed by Pennsylvania, Rhode Island, 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 September 2016, the State of Rhode Island also filed a lawsuit alleging that we and other major oil companies damaged the groundwater in Rhode Island by introducing thereto gasoline with MTBE. The suit filed in Rhode Island is proceeding in Federal court. 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 September 2003, we received a directive from the New Jersey Department of Environmental Protection (NJDEP) to remediate contamination in the sediments of the Lower Passaic River. The NJDEP is also seeking natural resource damages. The directive, insofar as it affects us, relates to alleged releases from a petroleum bulk storage terminal in Newark, New Jersey we previously owned. We and over 70 companies entered into an Administrative Order on Consent with the Environmental Protection Agency (EPA) to study the same contamination; this work remains ongoing. We and other parties settled a cost recovery claim by the State of New Jersey and agreed with the EPA to fund remediation of a portion of the site. On March 4, 2016, the EPA issued a Record of Decision (ROD) in respect of the lower eight miles of the Lower Passaic River, selecting a remedy that includes bank-to-bank dredging at an estimated cost of $1.38 billion. The ROD does not address the upper nine miles of the Lower Passaic River or the Newark Bay, which may require additional remedial action. In addition, the Federal trustees for natural resources have begun a separate assessment of damages to natural resources in the Passaic River. Given that the EPA has not selected a remedy for the entirety of the Lower Passaic River or the Newark Bay, total remedial costs cannot be reliably estimated at this time. Based on currently known facts and circumstances, we do not believe that this matter will result in a significant liability to us because our former terminal did not store or use contaminants which are of concern in the river sediments and could not have contributed contamination along the river’s length. Further, there are numerous other parties who we expect will bear the cost of remediation and damages.

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 is anticipated to begin in the fourth quarter of 2020. The costs will continue to be allocated amongst the parties, as they were for the Remedial Design.

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. The ultimate impact of these 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, but is not expected to be material.

From time to time, we are involved in other judicial and administrative proceedings, including proceedings relating to other environmental matters. 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.

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

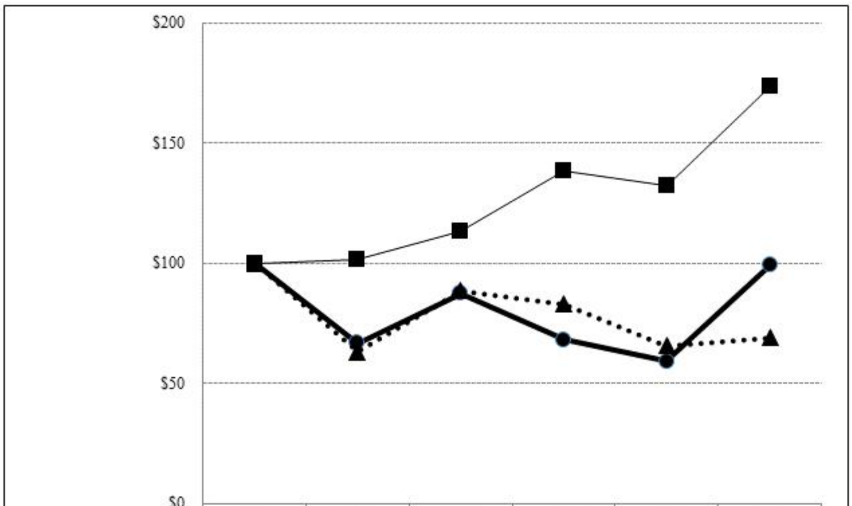
Our common stock is traded principally on the New York Stock Exchange (ticker symbol: HES). At January 31, 2020, there were 2,944 stockholders (based on the number of holders of record) who owned a total of 305,214,587 shares of common stock. In 2019, 2018 and 2017, cash dividends on common stock totaled $1.00 per share per year ($0.25 per quarter).

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.
- Proxy Peer Group comprising 12 oil and gas peer companies, including us, as disclosed in our 2019 Proxy Statement, excluding Anadarko Petroleum Corporation, which was acquired in August 2019.

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



	2014	2015	2016	2017	2018	2019
Hess Corporation	$100.00	$66.78	$87.42	$68.13	$59.17	$99.25
S&P 500	$100.00	$101.37	$113.49	$138.26	$132.19	$173.80
Proxy Peer Group	$100.00	$63.20	$88.46	$82.83	$65.64	$69.06

Share Repurchase Activities

Our share repurchases for the year ended December 31, 2019, were as follows:

2019	Total Number of Shares Purchased (a) (b)	Average Price Paid per Share (a)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (c)	Maximum Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs (d) (In millions)
March 1, 2019 through March 31, 2019	32,260	$ 56.62	—	$ 650
Total for 2019	32,260	$ 56.62	—	

(a) Repurchased in open-market transactions. The average price paid per share was inclusive of transaction fees.
(b) All of the shares repurchased were subsequently granted to Directors in accordance with the Non-Employee Directors' Stock Award Plan.
(c) Since initiation of the buyback program in August 2013, total shares repurchased through December 31, 2019 amounted to 91.9 million at a total cost of $6.85 billion including transaction fees.
(d) In March 2013, we announced that our Board of Directors approved a stock repurchase program that authorized the purchase of common stock up to a value of $4.0 billion. In May 2014, the share repurchase program was increased to $6.5 billion and in March 2018, it was increased further to $7.5 billion.

Equity Compensation Plans

Following is information related to our equity compensation plans at December 31, 2019.

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	4,300,802 (a)	$ 63.24	16,385,179 (b)
Equity compensation plans not approved by security holders (c)	—	—	—

(a) This amount includes 4,300,802 shares of common stock issuable upon exercise of outstanding stock options. This amount excludes 929,025 performance share units (PSUs) for which the number of shares of common stock to be issued may range from 0% to 200%, based on our total shareholder return (TSR) relative to the TSR of a predetermined group of peer companies over a three-year performance period ending December 31 of the year prior to settlement of the grant. In addition, this amount also excludes 2,014,306 shares of common stock issued as restricted stock pursuant to our equity compensation plans.
(b) These securities may be awarded as stock options, restricted stock, PSUs or other awards permitted under our equity compensation plan.
(c) We have a Non-Employee Director's Stock Award Plan pursuant to which each of our non-employee directors received $175,000 in value of our common stock. These awards are made from shares we have purchased in the open market.

See *Note 11*, *Share-based Compensation* in the *Notes to Consolidated Financial Statements* for further discussion of our equity compensation plans.

Item 6. Selected Financial Data

The following is a five-year summary of selected financial data that should be read in conjunction with both our *Consolidated Financial Statements* and *Accompanying Notes, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* included elsewhere in this Annual Report:

	2019	2018	2017	2016	2015
	(In millions, except per share amounts)				
Income Statement Selected Financial Data					
Sales and other operating revenues					
Crude oil (a)	**$ 5,233**	$ 4,960	$ 4,239	$ 3,639	$ 5,259
Natural gas liquids (a)	**347**	533	457	264	244
Natural gas (a)	**876**	965	750	766	1,052
Other operating revenues (b)	**39**	(135)	20	93	81
Total Sales and other operating revenues	**$ 6,495**	$ 6,323	$ 5,466	$ 4,762	$ 6,636
Income (loss) from continuing operations	**$ (240)**	$ (115)	$ (3,941)	$ (6,076)	$ (2,959)
Income (loss) from discontinued operations	**—**	—	—	—	(48)
Net income (loss)	**$ (240)**	$ (115)	$ (3,941)	$ (6,076)	$ (3,007)
Less: Net income (loss) attributable to noncontrolling interests	**168**	167	133	56	49
Net income (loss) attributable to Hess Corporation	**$ (408) (d)**	$ (282) (e)	$ (4,074) (f)	$ (6,132) (g)	$ (3,056) (h)
Net Income (Loss) Attributable to Hess Corporation Per Common Share:					
Basic:					
Continuing operations	**$ (1.37)**	$ (1.10)	$ (13.12)	$ (19.92)	$ (10.61)
Discontinued operations	—	—	—	—	(0.17)
Net income (loss) per share	**$ (1.37)**	$ (1.10)	$ (13.12)	$ (19.92)	$ (10.78)
Diluted:					
Continuing operations	**$ (1.37)**	$ (1.10)	$ (13.12)	$ (19.92)	$ (10.61)
Discontinued operations	—	—	—	—	(0.17)
Net income (loss) per share	**$ (1.37)**	$ (1.10)	$ (13.12)	$ (19.92)	$ (10.78)
Balance Sheet Selected Financial Data					
Total assets	**$ 21,782**	$ 21,433	$ 23,112	$ 28,621	$ 34,157
Total debt and Finance lease obligations (c)	**$ 7,397**	$ 6,672	$ 6,977	$ 6,806	$ 6,592
Total equity	**$ 9,706**	$ 10,888	$ 12,354	$ 15,591	$ 20,401
Dividends Per Share					
Dividends per share of common stock	**$ 1.00**	$ 1.00	$ 1.00	$ 1.00	$ 1.00

(a) *Represents sales of Hess net production and purchased third-party volumes.*

(b) *Commencing with the adoption of Accounting Standards Codification (ASC) 606, Revenue from Contracts with Customers, using the modified retrospective method effective January 1, 2018, gains (losses) on commodity derivatives are included within Other operating revenue. Prior to January 1, 2018, gains (losses) on commodity derivatives were included within Crude oil revenues.*

(c) *At December 31, 2019 includes debt from our Midstream operating segment of $1,753 million that is non-recourse to Hess Corporation (2018: $981 million; 2017: $980 million; 2016: $733 million; 2015: $704 million).*

(d) *Includes an allocation of noncash income tax expense of $86 million that was previously a component of accumulated other comprehensive income related to our 2019 crude oil hedge contracts, an after-tax charge of $88 million related to a pension settlement, a charge after income taxes and noncontrolling interests of $16 million for transaction related costs for Hess Midstream Partners LP acquisition of HIP and corporate restructuring, and an after-tax charge of $19 million related to a settlement on historical cost recovery balances in the JDA. These charges were partially offset by a noncash income tax benefit of $60 million to reverse a valuation allowance against net deferred tax assets in Guyana upon achieving first production, and an after-tax gain of $22 million related to the sale of our remaining acreage in the Utica shale play.*

(e) *Includes after-tax charges of $221 million related to exit costs, settlement of legal claims related to a former downstream interest, and a loss from debt extinguishment. These charges were, partially offset by a noncash income tax benefit of $91 million primarily related to intraperiod income tax allocation requirements resulting from changes in fair value of our 2019 crude oil hedging program, and gains totaling $24 million related to asset sales.*

(f) *Includes after-tax impairment charges of $2,250 million (Gulf of Mexico and Norway), an after-tax dry hole and lease impairment charge of $280 million (Ghana), a combined after-tax loss of $91 million related to asset sales (Norway, Equatorial Guinea and Permian), and after-tax charges of $52 million primarily for de-designated crude oil hedging contracts and other exit costs.*

(g) *Includes noncash charges of $3,749 million to establish valuation allowances on deferred tax assets following a three-year cumulative loss and after-tax charges of $894 million primarily for dry hole and other exploration expenses, loss on debt extinguishment, offshore rig costs, severance, and impairment of older specification rail cars.*

(h) *Includes total after-tax charges of $1,943 million, including noncash charges of $1,483 million to write-off all goodwill associated with our Exploration and Production operating segment.*

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 Statements* and the *Notes to Consolidated Financial Statements*, which are included in this Form 10-K in Item 8, the information set forth in *Risk Factors* under Item 1A.

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, 2017 compared with the year ended December 31, 2018, which can be found in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* in our 2018 Annual Report on Form 10-K, which was filed with the Securities and Exchange Commission on February 21, 2019, and such comparisons are incorporated herein by reference.

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Overview

Hess Corporation is a global Exploration and Production (E&P) company engaged in exploration, development, production, transportation, purchase and sale of crude oil, NGL, and natural gas with production operations and development activities located primarily in the United States (U.S.), Guyana, the Malaysia/Thailand Joint Development Area (JDA), Malaysia, and Denmark. We conduct exploration activities primarily offshore Guyana, the U.S. Gulf of Mexico, and offshore Suriname and Canada. At the Stabroek Block (Hess 30%), offshore Guyana, we have announced sixteen significant discoveries. The Liza Phase 1 development achieved first production in December 2019, with peak production expected to reach up to 120,000 gross bopd. The Liza Phase 2 development was sanctioned in the second quarter of 2019 and is expected to start up by early 2022 with production reaching up to 220,000 gross bopd. The discovered resources to date on the Stabroek Block are expected to underpin the potential for at least five FPSOs producing more than 750,000 gross bopd by 2025.

Our Midstream operating segment, which is comprised of Hess Corporation's 47% consolidated ownership interest in Hess Midstream LP at December 31, 2019, 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 *Note 6, Hess Midstream* in the *Notes to Consolidated Financial Statements*.

2020 Outlook

Our E&P capital and exploratory expenditures are projected to be approximately $3.0 billion in 2020. Capital investment for our Midstream operations is expected to be approximately $350 million. Oil and gas net production in 2020 is forecast to be in the range of 330,000 boepd to 335,000 boepd excluding Libya, up from 290,000 boepd in 2019, excluding Libya. Currently, we have West Texas Intermediate (WTI) put options for calendar year 2020 with an average monthly floor price of $55 per barrel for 130,000 bopd, and Brent put options for calendar year 2020 with an average monthly floor price of $60 per barrel for 20,000 bopd.

Net cash provided by operating activities was $1,642 million in 2019, compared with $1,939 million in 2018, while net cash provided by operating activities before changes in operating assets and liabilities was $2,237 million in 2019 and $2,129 million in 2018. Capital expenditures for 2019 and 2018 were $2,992 million and $2,180 million, respectively. In 2020, based on current forward strip crude oil prices, we expect cash flow from operating activities, cash and cash equivalents existing at December 31, 2019 of $1.5 billion, and our available committed revolving credit facility will be sufficient to fund our capital investment program and dividends.

Consolidated Results

Net loss attributable to Hess Corporation was $408 million in 2019 (2018: $282 million). Excluding items affecting comparability of earnings between periods summarized on page 30, the adjusted net loss was $281 million in 2019 (2018: $176 million). Annual net production averaged 311,000 boepd in 2019 (2018: 277,000 boepd). Total proved reserves were 1,197 million boe at December 31, 2019 (2018: 1,192 million boe).

Significant 2019 Activities

The following is an update of significant E&P activities during 2019:

E&P assets:

- In North Dakota, net production from the Bakken shale play averaged 152,000 boepd (2018: 117,000 boepd), with net oil production up 22% to 93,000 bopd from 76,000 bopd in the prior year, primarily due to increased drilling activity and new plug and perf completion design. Natural gas and NGL production was also higher due to the increased drilling activity, additional natural gas captured with the start-up of the Little Missouri 4 natural gas processing plant in the third quarter of 2019 and additional NGL received under percentage of proceeds contracts resulting from lower NGL commodity pricing. During the year, we operated six rigs, drilled 160 wells and brought on production 156 wells. Effective 2019, all new production wells use plug and perf completions. We were able to reduce the average cost of a plug and perf well in 2019 to $6.8 million per well from $7.6 million in 2018.

  During 2020, we plan to operate six rigs, drill approximately 170 wells and bring approximately 175 wells on production. We forecast net production to average approximately 180,000 boepd in 2020 and to reach approximately 200,000 boepd by the end of 2020. In the third quarter of 2020, the Tioga Gas Plant will be shut down for approximately 45 days for a planned turnaround and tie-in of the plant expansion project which will increase gas processing capacity to 400 million cubic feet per day from 250 million cubic feet per day and is expected to be in service by mid-2021. The shutdown for the turnaround is expected to reduce 2020 average net production, mostly natural gas liquids and natural gas, by approximately 6,000 boepd. Commencing in 2021, we plan to reduce our rig count to four operated rigs and, at this level of activity, expect to hold net production relatively flat at approximately 200,000 boepd for at least five years.

- In the Gulf of Mexico, net production averaged 66,000 boepd (2018: 57,000 boepd). The increase in production was primarily due to the Conger and Penn State fields and a new well brought online at the Llano Field. We forecast Gulf of Mexico net production for 2020 to average approximately 65,000 boepd, which reflects the impact of planned maintenance at the Conger and Llano fields in the second quarter.

  In 2019, the Corporation announced a discovery at the Hess operated Esox-1 exploration well in Mississippi Canyon Block No. 726 (Hess 57%), which encountered approximately 191 feet of net pay in high-quality oil-bearing Miocene reservoirs. First production from the well was achieved in February 2020 as a tie-back to the Tubular Bells production facilities.

  During the fourth quarter of 2019, the operator, Kosmos Energy Ltd., commenced drilling of the Oldfield-1 exploration well (Hess 60%), located approximately 6 miles east of Esox-1. The well, which was completed in January 2020, did not encounter commercial quantities of hydrocarbons and 2019 results include $15 million in exploration expense for well costs incurred through December 31, 2019. We estimate approximately $15 million of exploration expense will be recognized in the first quarter of 2020 for well costs incurred after December 31, 2019.

- At the Stabroek Block (Hess 30%), offshore Guyana, which covers approximately 6.6 million acres, the operator Esso Exploration and Production Guyana Limited has made sixteen significant discoveries since 2015. The discovered resources to date on the Stabroek Block are expected to underpin the potential for at least five FPSOs producing more than 750,000 gross bopd by 2025.

  The Liza Phase 1 development, which was sanctioned in 2017, began producing oil in December 2019 from the Liza Destiny FPSO. Production is expected to ramp up to the full capacity of 120,000 gross bopd in 2020. We forecast net production for 2020 to average approximately 25,000 bopd.

  The Liza Phase 2 development was sanctioned in 2019 and will utilize the Liza Unity FPSO to produce up to 220,000 gross bopd, with first production expected by early 2022. Six drill centers are planned with a total of 30 wells, including 15 production wells, nine water injection wells and six gas injection wells. In 2020, the operator plans to commence development drilling, installation of subsea flow lines and equipment, and installation of topside facilities modules on the Liza Unity FPSO.

  A third development, at the Payara Field, is expected to be sanctioned following government and regulatory approvals and is expected to produce up to 220,000 gross bopd with startup as early as 2023. In addition to the first three developments, planning is underway for additional FPSOs. The ultimate sizing and timing of these potential developments will be a function of further exploration and appraisal drilling.

  In 2019, five successful exploration wells and three successful appraisal wells were drilled on the Stabroek Block. See detailed well results on page 9 of *Items 1 and 2. Business and Properties.*

- In the Gulf of Thailand, net production from Block A-18 of the JDA averaged 35,000 boepd for the year (2018: 36,000 boepd), including contribution from unitized acreage in Malaysia, while net production from North Malay

Basin averaged 28,000 boepd for the year (2018: 27,000 boepd). During 2019, we drilled six production wells at North Malay Basin, and plan to continue the drilling program and development activities in 2020. We also expect to commence drilling activities in the fourth quarter of 2020 at the JDA. Combined net production from our JDA and North Malay Basin assets is forecast to average approximately 60,000 boepd in 2020.

The following is an update of significant Midstream activities during 2019:

- In March, Hess Infrastructure Partners LP (HIP) completed the acquisition of Hess' water services business for $225 million in cash.
- In March, HIP and Hess Midstream Partners LP acquired crude oil and gas gathering assets, and HIP acquired water gathering assets of Summit Midstream Partners LP's Tioga Gathering System for aggregate cash consideration of approximately $90 million, with the potential for an additional $10 million of contingent payments in future periods subject to certain future performance metrics.
- The Little Missouri 4 gas processing plant, a 50/50 joint venture between Hess Midstream LP and Targa Resources Corp., was placed in service during the third quarter.
- In December, Hess Midstream Partners LP completed the acquisition of HIP and converted its organizational structure from a master limited partnership into an "Up-C" structure in which Hess Midstream Partners LP's public unitholders received newly issued Class A shares in a new public entity named Hess Midstream LP (Hess Midstream). Upon completion of the transaction, we received consideration of $301 million in cash and additional equity interests in Hess Midstream LP, resulting in Hess Corporation's 47% consolidated ownership in Hess Midstream LP. See *Note 6, Hess Midstream* and *Note 8, Debt* in the *Notes to Consolidated Financial Statements*.

Liquidity and Capital and Exploratory Expenditures

In 2019, net cash provided by operating activities was $1,642 million (2018: $1,939 million). At December 31, 2019, consolidated cash and cash equivalents were $1,545 million (2018: $2,694 million), consolidated debt was $7,142 million (2018: $6,672 million, including capital lease obligations), and our consolidated debt to capitalization ratio was 43.2% (2018: 38.0%). Hess Midstream debt, which is nonrecourse to Hess Corporation, was $1,753 million at December 31, 2019 (2018: $981 million).

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

	2019	2018	2017
E&P Capital and Exploratory Expenditures:			
United States			
Bakken	**$ 1,312**	$ 967	$ 624
Other Onshore	**45**	43	30
Total Onshore	**1,357**	1,010	654
Offshore	**426**	368	702
Total United States	**1,783**	1,378	1,356
Guyana	**783**	383	236
Europe	**40**	8	142
Asia and Other	**137**	300	313
E&P - Capital and Exploratory Expenditures	**$ 2,743**	$ 2,069	$ 2,047
Exploration Expenses Charged to Income Included Above:			
United States	**$ 105**	$ 106	$ 90
International	**62**	54	105
Total Exploration Expenses Charged to Income included above	**$ 167**	$ 160	$ 195
Midstream Capital Expenditures:			
Midstream - Capital Expenditures (a)	**$ 416**	$ 271	$ 121

(a) Excludes equity investments of $33 million in 2019 (2018: $67 million).

In 2020, we project our E&P capital and exploratory expenditures will be approximately $3.0 billion and Midstream capital expenditures to be approximately $350 million.

Consolidated Results of Operations

Results by Segment:

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

	2019	2018	2017
		(In millions, except per share amounts)	
Net Income (Loss) Attributable to Hess Corporation:			
Exploration and Production	**$ 53**	$ 51	$ (3,653)
Midstream	**144**	120	42
Corporate, Interest and Other	**(605)**	(453)	(463)
Total	**$ (408)**	$ (282)	$ (4,074)
Net Income (Loss) Attributable to Hess Corporation Per Common Share - Diluted (a)	**$ (1.37)**	$ (1.10)	$ (13.12)

(a) Calculated as net income (loss) attributable to Hess Corporation less preferred stock dividends, divided by weighted average number of diluted shares.

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 items of income (expense) that are included in net income (loss) and affect comparability of earnings between periods. The items in the table below are explained on pages 36 through 39.

	2019	2018	2017
		(In millions)	
Items Affecting Comparability of Earnings Between Periods, After Income Taxes:			
Exploration and Production	**$ 63**	$ (86)	$ (2,609)
Midstream	**(16)**	—	(34)
Corporate, Interest and Other	**(174)**	(20)	(30)
Total	**$ (127)**	$ (106)	$ (2,673)

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 55. The items in the table below are explained on pages 36 through 39.

	Before Income Taxes		
	2019	2018	2017
		(In millions)	
Sales and other operating revenues	**$ —**	$ —	$ (22)
Gains (losses) on asset sales, net	**22**	24	(98)
Other, net	**(88)**	—	—
Marketing, including purchased oil and gas	**(21)**	—	—
Operating costs and expenses	**—**	(19)	—
Exploration expenses, including dry holes and lease impairment	**—**	(3)	(280)
General and administrative expenses	**(30)**	(130)	(11)
Loss on debt extinguishment	**—**	(53)	—
Depreciation, depletion and amortization	**—**	(16)	(19)
Impairment	**—**	—	(4,203)
Total Items Affecting Comparability of Earnings Between Periods, Pre-Tax	**$ (117)**	$ (197)	$ (4,633)

Reconciliations of GAAP and non-GAAP measures:

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

	2019	2018	2017
		(In millions)	
Adjusted Net Income (Loss) Attributable to Hess Corporation:			
Net income (loss) attributable to Hess Corporation	**$ (408)**	$ (282)	$ (4,074)
Less: Total items affecting comparability of earnings between periods, after-tax	**(127)**	(106)	(2,673)
Adjusted Net Income (Loss) Attributable to Hess Corporation	**$ (281)**	$ (176)	$ (1,401)

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:

	2019	2018	2017
		(In millions)	
Net cash provided by operating activities before changes in operating assets and liabilities:			
Net cash provided by (used in) operating activities	**$ 1,642**	$ 1,939	$ 945
Less: Changes in operating assets and liabilities	**(595)**	(190)	(799)
Net cash provided by (used in) operating activities before changes in operating assets and liabilities	**$ 2,237**	$ 2,129	$ 1,744

Adjusted net income (loss) attributable to Hess Corporation is a non-GAAP financial measure, which we define as reported net income (loss) attributable to Hess Corporation excluding items identified as affecting comparability of earnings between periods, which are summarized on pages 36 through 39. Management uses adjusted net income (loss) 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 U.S. GAAP net income (loss) 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:

	2019	2018	2017
		(In millions)	
Revenues and Non-Operating Income			
Sales and other operating revenues	**$ 6,495**	$ 6,323	$ 5,460
Gains (losses) on asset sales, net	**22**	27	(39)
Other, net	**51**	53	(1)
Total revenues and non-operating income	**6,568**	6,403	5,420
Costs and Expenses			
Marketing, including purchased oil and gas	**1,849**	1,833	1,335
Operating costs and expenses	**971**	941	1,248
Production and severance taxes	**184**	171	119
Midstream tariffs	**722**	648	543
Exploration expenses, including dry holes and lease impairment	**233**	362	507
General and administrative expenses	**204**	258	224
Depreciation, depletion and amortization	**1,977**	1,748	2,736
Impairment	**—**	—	4,203
Total costs and expenses	**6,140**	5,961	10,915
Results of Operations Before Income Taxes	**428**	442	(5,495)
Provision (benefit) for income taxes (a)	**375**	391	(1,842)
Net Income (Loss) Attributable to Hess Corporation	**$ 53**	$ 51	$ (3,653)

(a) Commencing January 1, 2019, management changed its measurement of segment earnings to reflect income taxes on a post U.S. tax consolidation and valuation allowance assessment basis. See footnote (a) in the table on page 86 for further details.

Excluding the E&P items affecting comparability of earnings between periods in the table on page 36, 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, depreciation, depletion and amortization, exploration expenses and income taxes, as discussed below.

Selling Prices: Average worldwide realized crude oil selling prices, including hedging, were 7% lower in 2019 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 2019 by 39% and worldwide natural gas prices decreased in 2019 by 7%, compared with the prior year. In total, lower realized selling prices decreased 2019 financial results by approximately $380 million after income taxes, compared with 2018. Our average selling prices were as follows:

	2019 (a)	2018 (a)	2017
Crude Oil - Per Barrel (Including Hedging)			
United States			
Onshore	**$ 53.19**	$ 56.90	$ 46.04
Offshore	**59.18**	62.02	47.34
Total United States	**55.15**	58.69	46.50
Europe	**66.29**	70.08	55.03
Africa	**64.91**	69.64	53.17
Asia	**61.81**	70.42	56.99
Worldwide	**56.77**	60.77	49.23
Crude Oil - Per Barrel (Excluding Hedging)			
United States			
Onshore	**$ 53.18**	$ 60.64	$ 46.76
Offshore	**59.17**	65.73	48.15
Total United States	**55.14**	62.41	47.25
Europe	**66.29**	70.08	55.14
Africa	**64.91**	69.64	53.25
Asia	**61.81**	70.42	56.99
Worldwide	**56.76**	63.80	49.75
Natural Gas Liquids - Per Barrel			
United States			
Onshore	**$ 13.20**	$ 21.29	$ 17.67
Offshore	**13.31**	25.58	21.34
Total United States	**13.21**	21.81	18.10
Europe	**—**	—	29.04
Worldwide	**13.21**	21.81	18.35
Natural Gas - Per Mcf			
United States			
Onshore	**$ 1.59**	$ 2.29	$ 1.96
Offshore	**2.12**	2.68	2.22
Total United States	**1.83**	2.43	2.03
Europe	**3.81**	3.61	4.42
Asia and other	**5.04**	5.07	4.27
Worldwide	**3.90**	4.18	3.37

(a) Selling prices in the United States are adjusted for certain processing and distribution fees included in Marketing expenses. Excluding these fees Worldwide selling prices for 2019 would be $59.95 per barrel for crude oil (including hedging) (2018: $63.77), $59.94 per barrel for crude oil (excluding hedging) (2018: $66.80), $13.40 per barrel for NGL (2018: $22.00) and $3.97 per mcf for natural gas (2018: $4.25).

Crude oil hedging activities were a net gain of $1 million before and after income taxes in 2019, and a loss of $183 million before and after income taxes in 2018. For calendar year 2020, we have WTI put options with an average monthly floor price of $55 per barrel for 130,000 bopd, and Brent put options with an average monthly floor price of $60 per barrel for 20,000 bopd. We expect noncash put option premium amortization, which will be reflected in realized selling prices, to reduce our 2020 results by approximately $70 million per quarter.

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

	2019	2018	2017
		(In thousands)	
Crude Oil - Barrels			
United States			
Bakken	**93**	76	67
Other Onshore (a)	**1**	1	6
Total Onshore	**94**	77	73
Offshore	**46**	41	39
Total United States	**140**	118	112
Europe (b)	**6**	6	28
Africa (c)	**19**	18	35
Asia and other	**4**	4	2
Worldwide	**169**	146	177
Natural Gas Liquids - Barrels			
United States			
Bakken	**41**	29	28
Other Onshore (a)	**1**	5	8
Total Onshore	**42**	34	36
Offshore	**5**	5	5
Total United States	**47**	39	41
Europe (b)	**—**	—	1
Worldwide	**47**	39	42
Natural Gas - Mcf			
United States			
Bakken	**107**	70	62
Other Onshore (a)	**3**	44	92
Total Onshore	**110**	114	154
Offshore	**91**	67	57
Total United States	**201**	181	211
Europe (b)	**7**	8	33
Asia and other	**364**	364	276
Worldwide	**572**	553	520
Barrels of Oil Equivalent	**311**	277	306
Crude oil and natural gas liquids as a share of total production	**69%**	67%	72%

(a) *The Corporation sold its Utica assets in August 2018. Production was 9,000 boepd for the year ended December 31, 2018 and 19,000 boepd for the year ended December 31, 2017. The Corporation sold its Permian assets in August 2017. Production was 4,000 boepd for the year ended December 31, 2017.*
(b) *The Corporation sold its Norway assets in December 2017. Production was 24,000 boepd for the year ended December 31, 2017.*
(c) *The Corporation sold its Equatorial Guinea assets in November 2017. Production was 25,000 boepd for the year ended December 31, 2017.*

In 2020, we expect net production, excluding Libya, to average between 330,000 boepd and 335,000 boepd, compared with 2019 net production, excluding Libya, of 290,000 boepd.

Net production variances related to 2019 and 2018 are summarized as follows:

United States: Bakken net oil production was higher in 2019, primarily due to increased drilling activity and new plug and perf completion design. Bakken net natural gas and NGL production was higher in 2019 also due to the increased drilling activity, additional natural gas captured with the start-up of the Little Missouri 4 natural gas processing plant in the third quarter of 2019 and additional NGL received under percentage of proceeds contracts resulting from lower NGL commodity pricing. The decline in U.S. other onshore net production from 2018 reflects the sale of our interests in the Utica shale play in August 2018. U.S. offshore net production increased in 2019, primarily due to higher production from the Conger and Penn State fields and a new well brought online at the Llano Field.

International: In Europe, Africa and Asia, net production was comparable in 2019 with 2018.

Sales Volumes: The impact of higher sales volumes from our net production improved after-tax results by approximately $560 million in 2019, compared with 2018.

Net worldwide sales volumes from Hess net production, which excludes sales volumes of crude oil, NGL and natural gas purchased from third parties, were as follows:

	2019	2018	2017
		(In thousands)	
Crude oil – barrels	**61,061**	52,742	63,367
Natural gas liquids – barrels	**17,067**	14,019	15,152
Natural gas – mcf	**208,665**	202,041	190,089
Barrels of Oil Equivalent	**112,906**	100,435	110,201
Crude oil - barrels per day	**167**	144	173
Natural gas liquids - barrels per day	**47**	39	42
Natural gas - mcf per day	**572**	553	520
Barrels of Oil Equivalent Per Day	**309**	275	302

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. marketing activities. Marketing expense for 2019 is comparable to 2018 primarily due to lower benchmark crude oil prices on the cost of purchased volumes being largely offset by higher purchases of third-party volumes.

Cash Operating Costs: Cash operating costs, consisting of operating costs and expenses, production and severance taxes and E&P general and administrative expenses, decreased $11 million in 2019, compared to 2018. Cash operating costs in 2018 included pre-tax charges totaling $91 million for vacated office space and severance costs, which more than offset increased costs from higher production in 2019. On a per-unit basis, cash operating costs improved from 2018 reflecting higher net production volumes in 2019. See *Exit Costs and Other* in *Items Affecting Comparability of Earnings Between Periods* on page 37.

Midstream Tariffs Expense: Tariffs expense increased from 2018, primarily due to higher throughput volumes in 2019. In 2020, we estimate Midstream tariffs expense to be in the range of $940 million to $965 million.

Depreciation, Depletion and Amortization (DD&A): DD&A costs increased by $229 million from 2018 primarily due to higher net production volumes in the Bakken and Gulf of Mexico.

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

	Actual			Forecast range (a)
	2019	2018	2017	2020
Cash operating costs (b)	**$ 11.99**	$ 12.66	$ 14.27	$11.50 — $12.50
DD&A (c)	**17.43**	17.14	24.53	16.50 — 17.50
Total Production Unit Costs	**$ 29.42**	$ 29.80	$ 38.80	$28.00 — $30.00

(a) Forecast information excludes any contribution from Libya.
(b) Cash operating costs per boe, excluding Libya, was $12.54 in 2019 (2018: $13.32).
(c) DD&A per boe, excluding Libya, was $18.52 in 2019 (2018: $18.29).

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

	2019	2018	2017
		(In millions)	
Exploratory dry hole costs	**$ 49**	$ 165	$ 268
Exploration lease and other impairment	**17**	37	44
Geological and geophysical expense and exploration overhead	**167**	160	195
	$ 233	$ 362	$ 507

In 2019, dry hole costs primarily related to the Jill-1 well on License 6/16 in Denmark and the Oldfield-1 well in the Gulf of Mexico. In 2018, dry hole costs primarily related to the Aspy well, offshore Nova Scotia, Canada; the Pontoenoe-1 well, offshore Suriname and the Sorubim-1 well on the Stabroek Block, offshore Guyana. In 2020, we estimate exploration expenses, excluding dry hole expense, to be in the range of $210 million to $220 million.

Income Taxes: In 2019, income tax expense was $375 million (2018: $391 million), primarily related to our operations in Libya. Commencing in 2017, we are generally not recognizing deferred tax benefit or expense in certain countries, primarily the U.S., Denmark (hydrocarbon tax only), Malaysia and Guyana (until December 2019), while we maintain valuation allowances against net deferred tax assets in these jurisdictions in accordance with the requirements of U.S. accounting standards. At December 31, 2019 the valuation allowance established against the net deferred tax asset in Guyana for the Stabroek Block was released as a result of the positive evidence from first production in December 2019, and the significant forecasted pre-tax income from operations. The cumulative pre-tax losses in Guyana were driven by pre-production activities. See E&P items affecting comparability of earnings below.

Actual effective tax rates are as follows:

	2019	2018	2017
	%	%	%
Effective income tax benefit (expense) rate	**(88)**	(88)	34
Adjusted effective income tax benefit (expense) rate (a)	**(36)**	60	7

(a) Excludes any contribution from Libya and items affecting comparability of earnings.

In 2020, we estimate income tax expense, excluding Libya and items affecting comparability of earnings between periods, to be in the range of $80 million to $90 million.

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

	Before Income Taxes			After Income Taxes		
	2019	2018	2017	2019	2018	2017
	(In millions)					
Gains (losses) on asset sales, net	**$ 22**	$ 24	$ (41)	**$ 22**	$ 24	$ (57)
Cost recovery settlement	**(21)**	—	—	**(19)**	—	—
Exit costs and other	**—**	(110)	—	**—**	(110)	—
Impairment	**—**	—	(4,203)	**—**	—	(2,250)
Dry hole, lease impairment and other exploration expenses	**—**	—	(280)	**—**	—	(280)
Noncash charges on de-designated crude oil collars	**—**	—	(22)	**—**	—	(22)
Reversal of deferred tax asset valuation allowance	**—**	—	—	**60**	—	—
	$ 1	$ (86)	$ (4,546)	**$ 63**	$ (86)	$ (2,609)

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		
	2019	2018	2017
	(In millions)		
Sales and other operating revenues	**$ —**	$ —	$ (22)
Gains (losses) on asset sales, net	**22**	24	(41)
Marketing, including purchased oil and gas	**(21)**	—	—
Operating costs and expenses	**—**	(19)	—
Exploration expenses, including dry holes and lease impairment	**—**	(3)	(280)
General and administrative expenses	**—**	(72)	—
Depreciation, depletion and amortization	**—**	(16)	—
Impairment	**—**	—	(4,203)
	$ 1	$ (86)	$ (4,546)

2019:

- *Gains (losses) on asset sales, net:* We recorded a pre-tax gain of $22 million ($22 million after income taxes) associated with the sale of our remaining acreage in the Utica shale play.
- *Cost recovery settlement:* We recorded a pre-tax charge of $21 million ($19 million after income taxes) related to a settlement on historical cost recovery balances in the JDA that was paid in cash.
- *Reversal of deferred tax asset valuation allowance:* We recorded a noncash income tax benefit of $60 million, which resulted from the reversal of a valuation allowance against net deferred tax assets in Guyana upon achieving first production from the Liza Phase 1 development.

2018:

- *Gains (losses) on asset sales, net:* We recorded a pre-tax gain of $14 million ($14 million after income taxes) associated with the sale of our joint venture interests in the Utica shale play in eastern Ohio and a pre-tax gain of $10 million ($10 million after income taxes) associated with the sale of our interests in Ghana.
- *Exit costs and other:* We incurred noncash pre-tax charges of $73 million ($73 million after income taxes) in connection with vacated office space. In addition, we recorded a pre-tax severance charge of $37 million ($37 million after income taxes), related to a cost reduction program undertaken to reflect the reduced scale of our business following significant asset sales in 2017.

2017:

- *Gains (losses) on asset sales, net:* We recognized a pre-tax gain of $486 million ($486 million after income taxes) related to the sale of our assets in Equatorial Guinea, and a pre-tax gain of $330 million ($314 million after income taxes) related to the sale of our enhanced oil recovery assets in the Permian Basin. We also incurred a pre-tax loss of $857 million ($857 million after income taxes) on the sale of our interests in Norway. The loss included the recognition of $900 million in earnings for cumulative translation adjustments previously reflected within accumulated other comprehensive income. See *Note 3, Dispositions* in the *Notes to Consolidated Financial Statements*.
- *Impairment:* We recorded a noncash impairment charge related to our interests in Norway totaling $2,503 million pre-tax ($550 million after income taxes) in the third quarter prior to the sale of our interests in the fourth quarter. In addition, we recognized pre-tax impairment charges to reduce the carrying value of our interests in the Stampede Field by $1,095 million ($1,095 million after income taxes), and the Tubular Bells Field by $605 million ($605 million after income taxes) primarily because of a lower long-term crude oil price outlook. The Stampede Field had significant capitalized exploration and appraisal costs that were incurred on a 100% working interest basis on the Pony discovery prior to unitizing into the Stampede project. See *Note 13, Impairment* in the *Notes to Consolidated Financial Statements*.
- *Dry hole, lease impairment and other exploration expenses:* We recorded a pre-tax charge of $280 million ($280 million after income taxes) to fully impair the carrying value of our interest at the Hess operated offshore Deepwater Tano/Cape Three Points license, offshore Ghana (Hess 50% license interest) as a result of management's decision in the fourth quarter of 2017 to not develop the previously discovered fields. These costs were incurred in periods prior to 2017.
- *Noncash charges on de-designated crude oil collars:* We recorded a pre-tax charge of $22 million ($22 million after income taxes) related to certain crude oil collars not designated as cash flow hedges. The de-designation was a result of production downtime caused by a fire at the third-party operated Enchilada platform in the Gulf of Mexico during the fourth quarter.

Midstream

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

	2019	2018	2017
		(In millions)	
Revenues and Non-Operating Income			
Sales and other operating revenues	**$ 848**	$ 713	$ 617
Losses on asset sales, net	**—**	—	(51)
Other, net	**4**	6	—
Total revenues and non-operating income	**852**	719	566
Costs and Expenses			
Operating costs and expenses	**279**	193	195
General and administrative expenses	**56**	14	16
Depreciation, depletion and amortization	**142**	127	123
Interest expense	**63**	60	26
Total costs and expenses	**540**	394	360
Results of Operations Before Income Taxes	**312**	325	206
Provision (benefit) for income taxes (a)	—	38	31
Net income (loss)	**312**	287	175
Less: Net income (loss) attributable to noncontrolling interests	**168**	167	133
Net Income (Loss) Attributable to Hess Corporation	**$ 144**	$ 120	$ 42

(a) Commencing January 1, 2019, management changed its measurement of segment earnings to reflect income taxes on a post U.S. tax consolidation and valuation allowance assessment basis. See footnote (a) in the table on page 86 for further details.

Sales and other operating revenues increased from 2018 primarily due to higher throughput volumes, increased rail transportation and water trucking revenues associated with third-party services, and higher tariff rates.

Operating costs and expenses increased from 2018, primarily due to higher maintenance activity, and increased third party rail transportation and water trucking charges. General and administrative expenses increased in 2019, compared to 2018, as a result of expenditures incurred from Hess Midstream Partners LP's acquisition of HIP and its corporate restructuring. See *Items Affecting Comparability of Earnings Between Periods* below. DD&A expenses increased from 2018 primarily due to additional assets places in service, including those related to the Summit acquisition.

The increase in interest expense from 2018 reflects higher borrowings by the Midstream business.

In 2020, we estimate net income attributable to Hess Corporation from the Midstream segment to be in the range of $205 million to $215 million.

Items Affecting Comparability of Earnings Between Periods: In 2019, we recognized a pre-tax charge of $30 million ($16 million after income taxes and noncontrolling interests) for transaction related costs for Hess Midstream Partners LP's acquisition of HIP and associated corporate restructuring. See *Note 6, Hess Midstream* in the *Notes to Consolidated Financial Statements.* In 2017, we recognized a pre-tax loss of $57 million ($34 million after income taxes and noncontrolling interests) related to the sale of our Midstream assets in the Permian Basin.

Corporate, Interest and Other

The following table summarizes Corporate, Interest and Other expenses:

	2019	2018	2017
		(In millions)	
Corporate and other expenses (excluding items affecting comparability)	**$ 114**	$ 97	$ 160
Interest expense	**355**	359	385
Less: Capitalized interest	**(38)**	(20)	(86)
Interest expense, net	**317**	339	299
Corporate, Interest and Other expenses before income taxes	**431**	436	459
Provision (benefit) for income taxes	**—**	(3)	(26)
Net Corporate, Interest and Other expenses after income taxes	**431**	433	433
Items affecting comparability of earnings between periods, after income taxes	**174**	20	30
Total Corporate, Interest and Other Expenses After Income Taxes	**$ 605**	$ 453	$ 463

Corporate and other expenses, excluding items affecting comparability, increased from 2018 primarily due to lower interest income and a reduction in other non-operating income. In 2020, after-tax Corporate and other expenses, excluding items affecting comparability of earnings between periods, are estimated to be in the range of $115 million to $125 million.

Interest expense for 2019 is comparable to 2018. Capitalized interest increased from 2018 due to ongoing development activity in Guyana, including the sanction of the Liza Field Phase 2 development during 2019. In 2020, after-tax interest expense, net is estimated to be in the range of $350 million to $360 million. The estimated increase in 2020 is due to ceasing interest capitalization at the Liza Field, which commenced production in December 2019.

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

2019:

- *Pension settlement:* We recorded a noncash pension settlement charge of $88 million ($88 million after income taxes) associated with the purchase of a single premium annuity contract by the Hess Corporation Employees' Pension Plan to settle and transfer certain of its obligations to a third party. The charge is included in *Other, net* in the *Statement of Consolidated Income*. See *Note 10, Retirement Plans*, in the *Notes to Consolidated Financial Statements*.
- *Income tax:* We recorded an allocation of noncash income tax expense of $86 million that was previously a component of accumulated other comprehensive income related to our 2019 crude oil hedge contracts.

2018:

- *Loss on debt extinguishment:* We recorded a pre-tax charge of $53 million ($53 million after income taxes) related to the premium paid for debt repurchases. See *Note 8, Debt*, in the *Notes to Consolidated Financial Statements.*
- *Exit costs and other:* We recorded a pre-tax charge of $58 million ($58 million after income taxes) resulting from the settlement of legal claims related to former downstream interests.
- *Income tax:* We recorded an allocation of noncash income tax benefit of $91 million to offset the recognition of a noncash income tax expense recorded in other comprehensive income resulting primarily from changes in fair value of our 2019 crude oil hedge contracts.

2017:

- *Exit costs and other:* We recorded a pre-tax charge of $30 million ($30 million after income taxes) in connection with vacated office space, of which $11 million is included in General and administrative expenses and $19 million is included in Depreciation, depletion and amortization in the *Statement of Consolidated Income*.

Liquidity and Capital Resources

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

	2019	2018
	(In millions, except ratio)	
Cash and cash equivalents (a)	**$ 1,545**	$ 2,694
Current maturities of long-term debt	—	67
Total debt (b)	**7,142**	6,672
Total equity	**9,706**	10,888
Debt to capitalization ratio (c)	**43.2%**	38.0%

(a) Includes $3 million of cash attributable to our Midstream Segment at December 31, 2019 (2018: $109 million).
(b) Includes $1,753 million of debt outstanding from our Midstream Segment at December 31, 2019 (2018: $981 million) that is non-recourse to Hess Corporation.
(c) Total debt (including finance lease obligations) as a percentage of the sum of total debt (including finance lease obligations) plus equity. Prior to the adoption of ASC 842, Leases, finance lease obligations were included in debt.

Cash Flows

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

	2019	2018	2017
		(In millions)	
Net cash provided by (used in):			
Operating activities	$ 1,642	$ 1,939	$ 945
Investing activities	(2,843)	(1,566)	1,358
Financing activities	52	(2,526)	(188)
Net Increase (Decrease) in Cash and Cash Equivalents	$ (1,149)	$ (2,153)	$ 2,115

***Operating Activities*:** Net cash provided by operating activities was $1,642 million in 2019 (2018: $1,939 million), while net cash provided by operating activities before changes in operating assets and liabilities was $2,237 million in 2019 (2018: $2,129 million). Net cash provided by operating activities before changes in operating assets and liabilities increased from 2018 primarily due to higher net production volumes, partially offset by lower commodity prices. Changes in operating assets and liabilities in 2019 reduced net cash provided by operating activities by $595 million (2018: $190 million reduction), primarily from premiums paid on crude oil hedge contracts, abandonment expenditures, pension contributions and an increase in accounts receivable. Changes in operating assets and liabilities in 2018 primarily related to premiums on crude oil hedge contracts and abandonment expenditures.

Investing Activities: Total Additions to Property, Plant and Equipment were $2,829 million in 2019 (2018: $2,097 million). The increase in Additions to property, plant and equipment from 2018 is primarily related to increased drilling activity in the Bakken, increased exploration and development activity on the Stabroek Block, offshore Guyana, and the Midstream operating segment's acquisition of assets from Summit Midstream Partners LP. In 2019, Midstream equity investments in its 50/50 joint venture with Targa Resources were $33 million (2018: $67 million). Proceeds from asset sales were $22 million in 2019 (2018: $607 million; 2017: $3,296 million). See *Note 3, Dispositions* in the *Notes to Consolidated Financial Statements*.

Financing Activities: Repayments of debt were $8 million in 2019 (2018: $633 million) while borrowings with maturities in excess of 90 days of $760 million in 2019 related to our Midstream operating segment. Common and preferred stock dividends paid were $316 million in 2019 (2018: $345 million). We settled $25 million of common stock purchases in 2019 (2018: $1,365 million). Net cash outflows to noncontrolling interests were $353 million in 2019 (2018: $211 million).

Future Capital Requirements and Resources

At December 31, 2019, Hess Corporation, had $1.5 billion in cash and cash equivalents, excluding Midstream, and total liquidity, including available committed credit facilities, of approximately $5.4 billion. The Corporation has no significant near-term debt maturities. Currently, we have WTI put options for calendar year 2020 with an average monthly floor price of $55 per barrel for 130,000 bopd, and Brent put options for calendar year 2020 with an average monthly floor price of $60 per barrel for 20,000 bopd.

Net production in 2020 is forecast to be in the range of 330,000 boepd to 335,000 boepd, excluding Libya, and we expect our 2020 E&P capital and exploratory expenditures will be approximately $3.0 billion. In 2020, based on current forward strip crude oil prices, we expect cash flow from operating activities, cash and cash equivalents existing at December 31, 2019, and our available committed revolving credit facility will be sufficient to fund our capital investment program and dividends.

The table below summarizes the capacity, usage, and available capacity of our borrowing and letter of credit facilities at December 31, 2019:

	Expiration Date	Capacity	Borrowings	Letters of Credit Issued	Total Used	Available Capacity
				(In millions)		
Hess Corporation						
Revolving credit facility	May 2023	$ 3,500	$ —	$ —	$ —	$ 3,500
Committed lines	Various (a)	445	—	54	54	391
Uncommitted lines	Various (a)	218	—	218	218	—
Total - Hess Corporation		$ 4,163	$ —	$ 272	$ 272	$ 3,891
Midstream						
Revolving credit facility (b)	December 2024	$ 1,000	$ 32	$ —	$ 32	$ 968
Total - Midstream		$ 1,000	$ 32	$ —	$ 32	$ 968

(a) Committed and uncommitted lines have expiration dates throughout 2020.
(b) This credit facility may only be utilized by HESM Opco and is non-recourse to Hess Corporation.

Hess Corporation:

In 2019, the Corporation entered into a new $3.5 billion revolving credit facility with a maturity date of May 15, 2023, which replaced the Corporation's previous revolving credit facility that was scheduled to mature on January 21, 2021. The new facility, which is fully undrawn, can be used for borrowings and letters of credit. Borrowings on the new facility will generally bear interest at 1.30% above LIBOR, though the interest rate is subject to adjustment if the Corporation's credit rating changes. The facility is subject to customary representations, warranties and covenants, including a financial covenant limiting the ratio of Total Consolidated Debt to Total Capitalization (as such terms are defined in the credit agreement for the facility) of the Corporation and its consolidated subsidiaries to 65%, and customary events of default. At December 31, 2019, the Corporation was in compliance with its financial covenants.

We had $272 million in letters of credit outstanding at December 31, 2019 (2018: $284 million), which primarily relate to our international operations. See also *Note 19, Financial Risk Management Activities* in the *Notes to Consolidated Financial Statements.*

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

Midstream:

At December 31, 2019, Hess Midstream Operations LP (formerly Hess Midstream Partners LP, or HESM Opco), a consolidated subsidiary of Hess Midstream LP, had $1.4 billion of senior secured syndicated credit facilities maturing December 16, 2024, consisting of a $1.0 billion 5-year revolving credit facility and a fully drawn $400 million 5-year Term Loan A facility. The revolving credit facility can be used for borrowings and letters of credit to fund HESM Opco's operating activities, capital expenditures, distributions and for other general corporate purposes. Borrowings under the 5-year Term Loan A facility will generally bear interest at LIBOR plus an applicable margin ranging from 1.55% to 2.50%, while the applicable margin for the 5-year syndicated revolving credit facility ranges from 1.275% to 2.000%. 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, 2019. The credit facilities are secured by first-priority perfected liens on substantially all the presently owned and after-acquired 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, 2019, borrowings of $32 million were drawn under HESM Opco's revolving credit facility, and borrowings of $400 million, excluding deferred issuance costs, were drawn under HESM Opco's Term Loan A facility. Borrowings under these credit facilities are non-recourse to Hess Corporation.

Credit Ratings

Two of the three major credit rating agencies that rate the Corporation's debt have assigned an investment grade rating. At December 31, 2019, we have investment grade credit ratings from Standard and Poor's Ratings Services (BBB-) and Fitch Ratings (BBB-). Moody's Investors Service has rated our debt at Ba1. The consequence of lower credit ratings is an increase in interest rates and facility fees on our credit facilities, and the potential for additional required collateral under operating agreements, which are not material at December 31, 2019.

At December 31, 2019, HESM Opco's senior unsecured debt is rated BB+ by Standard and Poor's Ratings Services and Fitch Ratings, and Ba3 by Moody's Investors Service.

Contractual Obligations and Contingencies

The following table shows aggregate information about certain contractual obligations at December 31, 2019:

		Payments Due by Period			
	Total	**2020**	**2021 and 2022**	**2023 and 2024**	**Thereafter**
			(In millions)		
Total Debt (excludes interest) (a)	$ 7,220	$ —	$ 30	$ 702	$ 6,488
Finance Leases (b)	392	36	72	72	212
Operating Leases (b)	599	200	137	129	133
Purchase Obligations:					
Capital expenditures (b)	1,743	913	755	75	—
Operating expenses (b)	190	158	20	9	3
Transportation and related contracts (b)	1,009	231	424	246	108
Asset retirement obligations	2,172	127	202	45	1,798
Other liabilities	565	114	113	100	238

(a) We anticipate cash payments for interest on Total Debt of $422 million for 2020, $831 million for 2021-2022, $817 million for 2023-2024, and $3,640 million thereafter for a total of $5,710 million. These interest payments reflect our contractual obligations at December 31, 2019.

(b) Comprises obligations, including where we, as operator, have contracted directly with suppliers.

Capital expenditures represent amounts that we were contractually committed at December 31, 2019, including the portion of our planned capital expenditure program for 2020. Obligations for operating expenses include commitments for oil and gas production expenses, seismic purchases and other normal business expenses. Other liabilities reflect contractually committed obligations in the *Consolidated Balance Sheet* at December 31, 2019, including pension plan liabilities and estimates for uncertain income tax positions. The Corporation and certain of its subsidiaries primarily lease drilling rigs, equipment, logistical assets (offshore vessels, aircraft, and shorebases), and office space for varying periods. See Note 7, *Leases* in *Notes to Consolidated Financial Statements*.

Off-Balance Sheet Arrangements

At December 31, 2019, we had $272 million in letters of credit. See also *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 and Malaysia, Denmark, Libya, Suriname, and Canada. Therefore, we are subject to the risks associated with foreign operations, including political risk, tax law changes, currency risk, corruption, and acts of terrorism. See *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 *Item 1A. Risk Factors*, crude oil prices are volatile which can have an impact on our proved reserves. If crude oil prices in 2020 are at levels below that used in determining 2019 proved reserves, we may recognize negative revisions to our December 31, 2020 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 2020 above those used in determining 2019 proved reserves could result in positive revisions to proved developed and proved undeveloped reserves at December 31, 2020. It is difficult to estimate the magnitude of any potential net negative or positive change in proved reserves at December 31, 2020, due to numerous currently unknown factors, including 2020 crude oil prices, any revisions based on 2020 reservoir performance, and the levels to which industry costs will change in response to movements in commodity prices. A 10% change in proved developed and proved undeveloped reserves at December 31, 2019 would result in an approximate $200 million pre-tax change in depreciation, depletion, and amortization expense for 2020 based on projected production volumes. See the *Supplementary Oil and Gas Data* on pages 90 through 98 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 determined 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. While crude oil prices in 2019 were lower than last year, we could experience an asset impairment in the future if 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.

Midstream Joint Venture: 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 47% 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, which provide us the ability to control the operations of Hess Midstream LP.

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 recorded 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 recorded 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. Due to a sustained low commodity price environment, we remained in a three-year cumulative consolidated loss position at December 31, 2019. A three-year cumulative consolidated 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 U.S., Denmark (hydrocarbon tax only) and Malaysia while we maintain valuation allowances against net deferred tax assets in these jurisdictions. In December 2019, we reversed the valuation allowance of $60 million for Guyana upon achieving first production from the Liza Phase 1 development.

At December 31, 2019, the *Consolidated Balance Sheet* reflects a $4,734 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 estimates of future taxable income change or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as expected future growth.

Asset Retirement Obligations: We have material 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 *Consolidated Statement of Income*. See Note 9, *Asset Retirement Obligations*.

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 rate used for measuring the present value of future plan obligations: The discount rate used to estimate our projected benefit obligations 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, 2019, a 0.25% decrease in the discount rate assumption would increase projected benefit obligations by approximately $120 million and forecasted 2020 annual benefit expense by approximately $10 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 return on plan assets is developed from the expected future returns for each asset category, weighted by the target allocation of pension assets to that asset category. The future expected 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, 2019, a 0.25% decrease in the expected long-term rates of return on plan assets assumption would increase forecasted 2020 annual benefit expense by approximately $5 million.

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

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 commitment 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 receivable balances, and our credit is considered for accrued 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 of fair value assigned for each physical derivative and financial asset or liability 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 environment, health, safety and social responsibility (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.

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. We are committed to complying with all Greenhouse Gas (GHG) emissions regulations and the responsible management of GHG emissions at our facilities.

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, “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. At December 31, 2019, our reserve for estimated remediation liabilities was approximately $70 million. We expect that existing reserves for environmental liabilities will adequately cover costs to assess and remediate known sites. Our remediation spending was approximately $20 million in 2019 (2018: $15 million; 2017: $15 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.

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 or interest 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 Danish Krone, 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 seller of options, we receive a premium at the outset and bear the risk of unfavorable changes in the price of the commodity underlying the option. As a purchaser of options, we pay a premium at the outset and have the right to participate in the favorable price movements in the underlying commodities.

Financial Risk Management Activities

At December 31, 2019, outstanding total debt, which was substantially comprised of fixed rate debt instruments, had a carrying value of $7,142 million and a fair value of $8,242 million. A 15% increase or decrease in interest rates would decrease or increase the fair value of our fixed rate debt by approximately $450 million or $490 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.

We have WTI put options for calendar year 2020 with an average monthly floor price of $55 per barrel for 130,000 bopd, and Brent put options for calendar year 2020 with an average monthly floor price of $60 per barrel for 20,000 bopd. As of December 31, 2019, an assumed 10% increase in the forward WTI and Brent crude oil prices used in determining the fair value of our put options would reduce the fair value of these derivatives instruments by approximately $60 million, while an assumed 10% decrease in the same crude oil prices would increase the fair value of these derivative instruments by approximately $110 million.

We have outstanding foreign exchange contracts with a total notional amount of $90 million at December 31, 2019 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% weakening of the U.S. Dollar exchange rate is estimated to be a loss of approximately $5 million at December 31, 2019.

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, 2019.

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, 2019, as stated in their report, which is included herein.

By	/s/ John P. Rielly John P. Rielly Senior Vice President and Chief Financial Officer	By	/s/ John B. Hess John B. Hess Chief Executive Officer

February 20, 2020

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Hess Corporation

Opinion on Internal Control over Financial Reporting

We have audited Hess Corporation and consolidated subsidiaries' (the "Corporation") internal control over financial reporting as of December 31, 2019, 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 maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, 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, 2019 and 2018, the related statements of consolidated income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2019, and the related notes and our report dated February 20, 2020 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.

/s/ Ernst & Young LLP
New York, New York
February 20, 2020

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
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, 2019 and 2018, the related statements of consolidated income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2019, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the consolidated financial position of the Corporation at December 31, 2019 and 2018, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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 20, 2020 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 (SEC) 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 Matters

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

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 $13,792 million at December 31, 2019, and depreciation, depletion and amortization (DD&A) expense was $1,977 million for the year then ended. As described in Note 1 to the financial statements, the Corporation follows the successful efforts method of accounting for its oil and gas exploration and production activities. Under the successful efforts method of accounting, DD&A expense is recorded using the units-of-production method, based on proved oil and gas reserves, as estimated by petroleum engineering specialists, for property acquisition costs and proved developed oil and gas reserves, also estimated by petroleum engineering specialists, for oil and gas production facilities and wells. Proved oil and gas reserves are based on geological and engineering evaluations of estimated in-place hydrocarbon volumes using financial and non-financial inputs. Significant judgment is required by the Corporations' internal engineering staff in evaluating the geological and engineering data used to estimate reserves. Estimating proved reserves also requires the selection of inputs, including oil and natural gas price assumptions, future operating and capital costs assumptions and tax rates by jurisdiction, among others. Management used independent petroleum engineering specialists to audit approximately 80 percent of the Corporation's proved reserves at December 31, 2019 as prepared by the Corporation's internal engineering staff. Auditing the Corporation's DD&A expense calculation is complex because of our need to assess the reasonableness of management's determination of the inputs described above used in estimating proved oil and gas reserves and to use the work of the internal engineering staff and independent petroleum engineering specialists.
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. In addition, 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, on a sample basis and assessing the inputs for reasonableness based on review of corroborative evidence and consideration of any contrary evidence. For proved undeveloped reserves, we evaluated management's development plans for compliance with the SEC rule that undrilled locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time, by assessing consistency of the development projection with the Corporation's drill plan and the availability of capital relative to the drill plan. Additionally, we performed analytic and lookback procedures on inputs into the oil and gas reserve estimate as well as on the outputs. Finally, we tested the mathematical accuracy of the DD&A expense calculations, including comparing the proved oil and gas reserves to the Corporation's reserve report.
	Assessment of realizability of deferred tax assets
Description of the Matter	At December 31, 2019, the Corporation had $1,028 million of total deferred tax assets, net of valuation allowances, related to deductible temporary differences and net operating loss carryforwards in multiple jurisdictions. As described in Note 1 to the financial statements, the Corporation records a valuation allowance against its deferred tax assets if, based on the weight of all available evidence, in management's judgment it is more likely than not that some portion, or all, of the deferred tax assets will not be realized. Valuation allowances on deferred tax assets totaled $4,734 million as of December 31, 2019. Auditing management's assessment of the realizability of deferred tax assets was subjective because management's estimate was judgmental and involved assessing the weight of positive and negative evidence, often based on significant assumptions that may be affected by future market or economic conditions. This included, among other things, evaluation of the history of operating income or losses, the reversal of existing taxable temporary differences and forecasts of future taxable income (exclusive of reversing temporary differences and carryforwards).

How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design, and tested the operating effectiveness of the Corporation's controls that address the risks of material misstatement relating to the realizability of deferred tax assets, including, where applicable, controls over projections of future taxable income. We also tested management's controls over the completeness and accuracy of the data used in the estimates. Our audit procedures included, among others, evaluating management's weighting of positive and negative evidence in determining whether a valuation allowance was required as well as testing the material assumptions used by the Corporation to develop estimates of future taxable income, where applicable, by jurisdiction. We tested the underlying data used in the Corporation's projections, by comparing key inputs used to develop future taxable income with historical information as well as evaluating management's consideration of current industry conditions and economic trends incorporated in such projections.

/s/ Ernst & Young LLP
We have served as the Corporation's auditor since 1971
New York, New York
February 20, 2020

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	December 31, 2019	December 31, 2018
	(In millions, except share amounts)	
Assets		
Current Assets:		
Cash and cash equivalents	**$ 1,545**	$ 2,694
Accounts receivable:		
From contracts with customers	**940**	771
Joint venture and other	**230**	230
Inventories	**261**	245
Other current assets	**180**	519
Total current assets	**3,156**	4,459
Property, plant and equipment:		
Total — at cost	**35,820**	33,222
Less: Reserves for depreciation, depletion, amortization and lease impairment	**19,006**	17,139
Property, plant and equipment — net	**16,814**	16,083
Operating lease right-of-use assets — net	**447**	—
Finance lease right-of-use assets — net	**299**	—
Goodwill	**360**	360
Deferred income taxes	**80**	21
Other assets	**626**	510
Total Assets	**$ 21,782**	$ 21,433
Liabilities		
Current Liabilities:		
Accounts payable	**$ 411**	$ 495
Accrued liabilities	**1,803**	1,560
Taxes payable	**97**	81
Current maturities of long-term debt	**—**	67
Current portion of operating and finance lease obligations	**199**	—
Total current liabilities	**2,510**	2,203
Long-term debt	**7,142**	6,605
Long-term operating lease obligations	**353**	—
Long-term finance lease obligations	**238**	—
Deferred income taxes	**415**	421
Asset retirement obligations	**897**	741
Other liabilities and deferred credits	**521**	575
Total Liabilities	**12,076**	10,545
Equity		
Hess Corporation stockholders' equity:		
Preferred stock, par value $1.00; Authorized — 20,000,000 shares:		
Series A 8% Cumulative Mandatory Convertible; $1,000 per share liquidation preference; Issued — zero shares (2018: 574,997)	**—**	1
Common stock, par value $1.00; Authorized — 600,000,000 shares:		
Issued — 304,955,472 shares (2018: 291,434,534)	**305**	291
Capital in excess of par value	**5,591**	5,386
Retained earnings	**3,535**	4,257
Accumulated other comprehensive income (loss)	**(699)**	(306)
Total Hess Corporation stockholders' equity	**8,732**	9,629
Noncontrolling interests	**974**	1,259
Total equity	**9,706**	10,888
Total Liabilities and Equity	**$ 21,782**	$ 21,433

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

	Years Ended December 31,		
	2019	2018	2017
	(In millions, except per share amounts)		
Revenues and Non-Operating Income			
Sales and other operating revenues	**$ 6,495**	$ 6,323	$ 5,466
Gains (losses) on asset sales, net	**22**	32	(86)
Other, net	**(7)**	111	11
Total revenues and non-operating income	**6,510**	6,466	5,391
Costs and Expenses			
Marketing, including purchased oil and gas	**1,736**	1,771	1,267
Operating costs and expenses	**1,237**	1,134	1,443
Production and severance taxes	**184**	171	119
Exploration expenses, including dry holes and lease impairment	**233**	362	507
General and administrative expenses	**397**	473	422
Interest expense	**380**	399	325
Loss on debt extinguishment	**—**	53	—
Depreciation, depletion and amortization	**2,122**	1,883	2,883
Impairment	**—**	—	4,203
Total costs and expenses	**6,289**	6,246	11,169
Income (Loss) Before Income Taxes	**221**	220	(5,778)
Provision (benefit) for income taxes	**461**	335	(1,837)
Net Income (Loss)	**(240)**	(115)	(3,941)
Less: Net income (loss) attributable to noncontrolling interests	**168**	167	133
Net Income (Loss) Attributable to Hess Corporation	**(408)**	(282)	(4,074)
Less: Preferred stock dividends	**4**	46	46
Net Income (Loss) Attributable to Hess Corporation Common Stockholders	**$ (412)**	$ (328)	$ (4,120)
Net Income (Loss) Attributable to Hess Corporation Per Common Share			
Basic	**$ (1.37)**	$ (1.10)	$ (13.12)
Diluted	**$ (1.37)**	$ (1.10)	$ (13.12)
Weighted Average Number of Common Shares Outstanding (Diluted)	**301.2**	298.2	314.1
Common Stock Dividends Per Share	**$ 1.00**	$ 1.00	$ 1.00

See accompanying Notes to Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME

	Years Ended December 31,		
	2019	2018	2017
	(In millions)		
Net Income (Loss)	$ (240)	$ (115)	$ (3,941)
Other Comprehensive Income (Loss):			
Derivatives designated as cash flow hedges			
Effect of hedge (gains) losses reclassified to income	(1)	173	18
Income taxes on effect of hedge (gains) losses reclassified to income	—	—	—
Net effect of hedge (gains) losses reclassified to income	(1)	173	18
Change in fair value of cash flow hedges	(462)	330	(156)
Income taxes on change in fair value of cash flow hedges	86	(86)	—
Net change in fair value of cash flow hedges	(376)	244	(156)
Change in derivatives designated as cash flow hedges, after taxes	(377)	417	(138)
Pension and other postretirement plans			
(Increase) reduction in unrecognized actuarial losses	(160)	29	35
Income taxes on actuarial changes in plan liabilities	—	(6)	—
(Increase) reduction in unrecognized actuarial losses, net	(160)	23	35
Amortization of net actuarial losses	144	41	77
Income taxes on amortization of net actuarial losses	—	—	—
Net effect of amortization of net actuarial losses	144	41	77
Change in pension and other postretirement plans, after taxes	(16)	64	112
Foreign currency translation adjustment			
Foreign currency translation adjustment	—	—	144
Asset disposition	—	—	900
Change in foreign currency translation adjustment	—	—	1,044
Other Comprehensive Income (Loss)	(393)	481	1,018
Comprehensive Income (Loss)	(633)	366	(2,923)
Less: Comprehensive income (loss) attributable to noncontrolling interests	168	167	133
Comprehensive Income (Loss) Attributable to Hess Corporation	$ (801)	$ 199	$ (3,056)

See accompanying Notes to Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED CASH FLOWS

	Years Ended December 31,		
	2019	2018	2017
	(In millions)		
Cash Flows From Operating Activities			
Net income (loss)	$ (240)	$ (115)	$ (3,941)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
(Gains) losses on asset sales, net	(22)	(32)	86
Depreciation, depletion and amortization	2,122	1,883	2,883
Impairment	—	—	4,203
Exploratory dry hole costs	49	165	268
Exploration lease and other impairment	17	37	44
Pension settlement loss	93	4	19
Stock compensation expense	85	72	86
Noncash (gains) losses on commodity derivatives, net	116	182	97
Provision (benefit) for deferred income taxes and other tax accruals	17	(120)	(2,001)
Loss on debt extinguishment	—	53	—
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(383)	(138)	(340)
(Increase) decrease in inventories	(16)	(12)	(64)
Increase (decrease) in accounts payable and accrued liabilities	4	88	(44)
Increase (decrease) in taxes payable	16	(2)	(34)
Changes in other operating assets and liabilities	(216)	(126)	(317)
Net cash provided by (used in) operating activities	1,642	1,939	945
Cash Flows From Investing Activities			
Additions to property, plant and equipment - E&P	(2,433)	(1,854)	(1,788)
Additions to property, plant and equipment - Midstream	(396)	(243)	(149)
Payments for Midstream equity investments	(33)	(67)	—
Proceeds from asset sales, net of cash sold	22	607	3,296
Other, net	(3)	(9)	(1)
Net cash provided by (used in) investing activities	(2,843)	(1,566)	1,358
Cash Flows From Financing Activities			
Net borrowings (repayments) of debt with maturities of 90 days or less	32	—	(153)
Debt with maturities of greater than 90 days:			
Borrowings	760	—	800
Repayments	(8)	(633)	(459)
Payments on finance lease obligations	(49)	—	—
Proceeds from issuance of Hess Midstream Partnership LP units	—	—	366
Common stock acquired and retired	(25)	(1,365)	(110)
Cash dividends paid	(316)	(345)	(363)
Noncontrolling interests, net	(353)	(211)	(243)
Other, net	11	28	(26)
Net cash provided by (used in) financing activities	52	(2,526)	(188)
Net Increase (Decrease) in Cash and Cash Equivalents	(1,149)	(2,153)	2,115
Cash and Cash Equivalents at Beginning of Year	2,694	4,847	2,732
Cash and Cash Equivalents at End of Year	$ 1,545	$ 2,694	$ 4,847

See accompanying Notes to Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED EQUITY

	Mandatory Convertible Preferred Stock	Common Stock	Capital in Excess of Par	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Hess Stockholders' Equity	Noncontrolling Interests	Total Equity
					(In millions)			
Balance at December 31, 2016	$ 1	$ 317	$ 5,773	$ 10,147	$ (1,704)	$ 14,534	$ 1,057	$ 15,591
Cumulative effect of adoption of new accounting standards	—	—	2	(39)	—	(37)	—	(37)
Net income (loss)	—	—	—	(4,074)	—	(4,074)	133	(3,941)
Other comprehensive income (loss)	—	—	—	—	1,018	1,018	—	1,018
Share-based compensation	—	1	92	—	—	93	—	93
Dividends on preferred stock	—	—	—	(46)	—	(46)	—	(46)
Dividends on common stock	—	—	—	(317)	—	(317)	—	(317)
Common stock acquired and retired	—	(3)	(43)	(74)	—	(120)	—	(120)
Hess Midstream Partners LP units issuance	—	—	—	—	—	—	356	356
Noncontrolling interests, net	—	—	—	—	—	—	(243)	(243)
Balance at December 31, 2017	$ 1	$ 315	$ 5,824	$ 5,597	$ (686)	$ 11,051	$ 1,303	$ 12,354
Cumulative effect of adoption of new accounting standards	—	—	—	101	(101)	—	—	—
Net income (loss)	—	—	—	(282)	—	(282)	167	(115)
Other comprehensive income (loss)	—	—	—	—	481	481	—	481
Share-based compensation	—	1	103	—	—	104	—	104
Dividends on preferred stock	—	—	—	(46)	—	(46)	—	(46)
Dividends on common stock	—	—	—	(299)	—	(299)	—	(299)
Common stock acquired and retired	—	(25)	(541)	(814)	—	(1,380)	—	(1,380)
Noncontrolling interests, net	—	—	—	—	—	—	(211)	(211)
Balance at December 31, 2018	$ 1	$ 291	$ 5,386	$ 4,257	$ (306)	$ 9,629	$ 1,259	$ 10,888
Net income (loss)	—	—	—	(408)	—	(408)	168	(240)
Other comprehensive income (loss)	—	—	—	—	(393)	(393)	—	(393)
Preferred stock conversion	(1)	12	(11)	—	—	—	—	—
Share-based compensation	—	2	123	—	—	125	—	125
Dividends on preferred stock	—	—	—	(4)	—	(4)	—	(4)
Dividends on common stock	—	—	—	(310)	—	(310)	—	(310)
Conversion of Midstream structure	—	—	15	—	—	15	(22)	(7)
Sale of water business to Hess Infrastructure Partners	—	—	78	—	—	78	(78)	—
Noncontrolling interests, net	—	—	—	—	—	—	(353)	(353)
Balance at December 31, 2019	$ —	$ 305	$ 5,591	$ 3,535	$ (699)	$ 8,732	$ 974	$ 9,706

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 Exploration and Production (E&P) company engaged in exploration, development, production, transportation, purchase and sale of crude oil, NGL, and natural gas with production operations and development activities located primarily in the United States (U.S.), Guyana, the Malaysia/Thailand Joint Development Area (JDA), Malaysia and Denmark. We conduct exploration activities primarily offshore Guyana, the U.S. Gulf of Mexico, and offshore Suriname and Canada.

Our Midstream operating segment, which is comprised of Hess Corporation's 47% consolidated ownership interest in Hess Midstream LP at December 31, 2019 (see *Note 6, Hess Midstream*) 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.

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. Commencing December 16, 2019, we consolidate Hess Midstream LP, a variable interest entity that acquired Hess Infrastructure Partners LP (HIP), based on our conclusion that we have the power through Hess Corporation's 47% 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. Prior to December 16, 2019, we consolidated HIP, also a variable interest entity based on the conclusion we had the power to direct the activities that most significantly impact the economic performance of HIP. 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.

On January 1, 2019, we adopted Accounting Standards Codification (ASC) Topic 842, *Leases*. ASC 842 supersedes ASC 840 and requires the recognition of right-of-use (ROU) assets and lease obligations for all leases with lease terms greater than one year, including leases previously treated as operating leases under ASC 840. We adopted ASC 842 using the modified retrospective method which allows the standard to be applied prospectively. No cumulative effect adjustment was recorded to Retained Earnings at January 1, 2019, and comparative financial statements for periods prior to adoption of ASC 842 were not affected. We elected to apply a number of practical expedients permitted by the standard, including not needing to reassess: (i) whether existing contracts are (or contain) leases, (ii) whether the lease classification for existing leases would differ under ASC 842, (iii) whether initial direct costs incurred for existing leases are capitalizable under ASC 842, and (iv) land easements that were not previously accounted for as leases under ASC 840. We also elected to not recognize a lease liability or ROU asset for short-term leases as defined in ASC 842. This standard does not apply to leases acquired for oil and gas producing activities that are accounted for under ASC 932, *Extractive Activities – Oil and Gas*.

The adoption of ASC 842 did not have an impact on our *Statement of Consolidated Income* or *Statement of Consolidated Cash Flows*. The impact of adoption on our *Consolidated Balance Sheet* on January 1, 2019, was as follows:

	December 31, 2018	Adjustment for Finance Leases	Adjustment for Operating Leases	January 1, 2019
		(In millions)		
Assets				
Property, plant and equipment — net	$ 16,083	$ (346)	$ —	$ 15,737
Operating lease right-of-use assets — net	—	—	804	804
Finance lease right-of-use assets — net	—	346	—	346
Liabilities				
Accrued liabilities	1,560	—	(2)	1,558
Current maturities of long-term debt	67	(55)	—	12
Current portion of operating and finance lease obligations	—	55	382	437
Long-term debt	6,605	(254)	—	6,351
Long-term operating lease obligations	—	—	516	516
Long-term finance lease obligations	—	254	—	254
Other liabilities and deferred credits	575	—	(92)	483

In 2019, we adopted Accounting Standards Update (ASU) 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes*. This ASU makes certain targeted improvements to the accounting for income taxes by removing certain exceptions to the general principles in Topic 740, including removal of the exception to the incremental approach for intraperiod tax allocation when there is a loss from continuing operations and income or gain from other items, such as other comprehensive income. The amendments also improve consistent application of and simplify U.S. generally accepted accounting principles (GAAP) for other areas of Topic 740 by clarifying and amending existing guidance. This ASU is effective for us beginning in the first quarter of 2021, with early adoption permitted. We elected to adopt this ASU effective October 1, 2019, and the adoption had no impact on our Consolidated Financial Statements.

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 our *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, pension 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 the minimum volume commitment, 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 *Statement of Consolidated Income*.

Contract types:

The following is a summary of contract types for our E&P segment:

Crude oil, NGL, and natural gas – United States (U.S.): 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 twelve years. Contracts may specify a fixed volume for delivery subject to tolerance thresholds or may specify a percentage of production to be delivered from a particular location. Pricing is determined with reference to a particular market or pricing index, plus or minus adjustments reflecting quality or location differentials.

Crude oil – International: Contracts with customers for the sale of international crude oil involve the short-term sale of volumes during a specified period. These contracts specify a fixed volume for delivery subject to tolerance thresholds. 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.

Natural gas – 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 is determined using contractual formulas that are based on the price of alternative fuels as obtained from price indices and other factors. These contracts also specify a minimum volume we are obligated to make available during specified periods within the contract term and may specify minimum volumes the customer is obligated to purchase during specified periods within the contract term. If we do not deliver the volume properly nominated by the customer, the customer is entitled to a price discount on future volumes equivalent to the shortfall delivery. Under certain international natural gas sales agreements, if the customer purchases natural gas volumes below the minimum volume commitment, the customer is required to pay us for the shortfall volumes and may receive make-up volumes in subsequent periods at no additional cost.

Revenue from sale of third-party purchased volumes: Crude oil, NGL, and natural gas 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. The types of contracts with customers for the sale of third-party purchased volumes are the same as those described above.

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. At December 31, 2019 and 2018, there were no contract assets or contract liabilities.

Generally, we receive payments from customers on a monthly basis, shortly after the physical delivery of the crude oil, NGL, or natural gas. We did not recognize any credit losses on receivables with customers during 2019 nor 2018.

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 *ASC 606* 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.

Midstream

Our Midstream segment provides gathering, compression, processing, fractionation, storage, terminaling, loading and transportation, and water handling services.

The Midstream segment has multiple long-term, fee-based commercial agreements with a marketing subsidiary of Hess, each generally with an initial ten-year term that can be extended for an additional ten-year term at the unilateral right of our Midstream segment. These contracts have minimum volumes the customer is obligated to provide each calendar quarter. The minimum volume commitments are subject to fluctuation based on nominations covering substantially all of our E&P segment's production and projected third-party volumes that will be purchased in the Bakken. As the minimum volume commitments are subject to fluctuation, and as these contracts contain fee inflation escalators and fee recalculation mechanisms, substantially all of the transaction price at contract inception is variable. The Midstream segment also provides water handling services to a subsidiary of Hess for an agreed-upon fee per barrel or the reimbursement of third-party fees.

The Midstream segment's responsibilities to provide each of the above services for each year under each of the commercial agreements are considered separate, distinct performance obligations. Revenue is recognized for each performance obligation under these commercial agreements over-time as services are rendered using the output method, measured using the amount of volumes serviced during the period. The Midstream segment has elected the practical expedient under the provisions of *ASC 606, Revenue from Contracts with Customers* to recognize revenue in the amount it is entitled to invoice. If the commercial agreements have ship-or-pay provisions, the Midstream segment's responsibility to stand-ready to service a minimum volume over each quarterly commitment period represent separate, distinct performance obligations. Shortfall payments received under ship-or-pay provisions are recognized as revenue in the calendar quarter the shortfall occurs as the customer does not have make-up rights beyond the calendar quarter end of the quarterly commitment period. All revenues, receivables, and contract balances arising from the commercial agreements between the Midstream segment and the Hess marketing subsidiary that is 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 over the useful lives of the assets 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 determined 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 that the carrying amount of the goodwill may not be recoverable. To determine whether an indicator of impairment exists, the fair value of a reporting unit is compared with its carrying amount, 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 charge 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, 2019, 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: Unsold crude oil and NGL are valued at the lower of cost or net realizable value. Cost is determined based on the average cost of production. 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.

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 recorded 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 recorded 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 no longer 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 material 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, and the asset is depreciated over 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, which represent Level 3 inputs in the fair value hierarchy. 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*.

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 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 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 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 commitment 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 receivable balances, and our credit is considered for accrued 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 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 of fair value assigned for each physical derivative and financial asset or liability 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 under the fair value method of accounting. The fair value of all share-based compensation is recognized over the service period for the entire award, whether the award was granted with ratable or cliff vesting, 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 Translation: 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*. For our former operations in Norway that did not use the U.S. Dollar as the functional currency, adjustments resulting from translating foreign currency assets and liabilities into U.S. Dollars were recorded in a separate component of equity titled Accumulated other comprehensive income (loss) prior to the disposition. See *Note 3, Dispositions*.

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 2019, our reserve for estimated remediation liabilities was approximately $70 million. Environmental expenditures that increase the life or efficiency of property or reduce or prevent future adverse impacts to the environment are capitalized.

New Accounting Pronouncements: In June 2016, the FASB issued ASU 2016-13, *Financial Instruments – Credit Losses*. This ASU makes changes to the impairment model for trade receivables, net investments in leases, debt securities, loans and certain other instruments. The standard requires the use of a forward-looking "expected loss" model compared with the current "incurred loss" model. We will adopt this ASU in the first quarter of 2020 when the standard becomes effective and it is not expected to have a material impact on our consolidated financial statements.

2. Revenue

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

	Exploration and Production					Midstream	Eliminations	Total
	United States	Europe	Africa	Asia	E&P Total			
2019								
Sales of our net production volumes:								
Crude oil revenue	$ 2,981	$ 130	$ 436	$ 113	$ 3,660	$ —	$ —	$ 3,660
Natural gas liquids revenue	229	—	—	—	229	—	—	229
Natural gas revenue	150	9	24	646	829	—	—	829
Sales of purchased oil and gas	1,644	—	91	3	1,738	—	—	1,738
Intercompany revenue	—	—	—	—	—	848	(848)	—
Total revenues from contracts with customers	5,004	139	551	762	6,456	848	(848)	6,456
Other operating revenues (a)	39	—	—	—	39	—	—	39
Total sales and other operating revenues	$ 5,043	$ 139	$ 551	$ 762	$ 6,495	$ 848	$ (848)	$ 6,495

	Exploration and Production					Midstream	Eliminations	Total
	United States	Europe	Africa	Asia	E&P Total			
2018								
Sales of our net production volumes:								
Crude oil revenue	$ 2,832	$ 153	$ 434	$ 104	$ 3,523	$ —	$ —	$ 3,523
Natural gas liquids revenue	308	—	—	—	308	—	—	308
Natural gas revenue	176	11	21	651	859	—	—	859
Sales of purchased oil and gas	1,661	—	93	14	1,768	—	—	1,768
Intercompany revenue	—	—	—	—	—	713	(713)	—
Total revenues from contracts with customers	4,977	164	548	769	6,458	713	(713)	6,458
Other operating revenues (a)	(135)	—	—	—	(135)	—	—	(135)
Total sales and other operating revenues	$ 4,842	$ 164	$ 548	$ 769	$ 6,323	$ 713	$ (713)	$ 6,323

(a) Includes gains (losses) on commodity derivatives.

3. Dispositions

2019: We completed the sale of our remaining acreage in the Utica shale play in eastern Ohio for proceeds of $22 million, after normal closing adjustments, and recognized a pre-tax gain of $22 million ($22 million after income taxes).

2018: We completed the sale of our joint venture interests in the Utica shale play in eastern Ohio in August for proceeds of $396 million, after normal closing adjustments, and recognized a pre-tax gain of $14 million ($14 million after income taxes). In addition, we completed the sale of our interests in Ghana for total consideration of $100 million, consisting of a $25 million payment that was received at closing and a further payment of $75 million that is payable to us upon the buyer receiving government approval for a Plan of Development on the Deepwater Tano Cape Three Points Block. The receipt of proceeds at closing resulted in a pre-tax gain of $10 million ($10 million after income taxes).

2017: We completed the sale of our enhanced oil recovery assets in the Permian Basin in August for proceeds of $597 million, after normal closing adjustments, and recognized a pre-tax gain of $273 million ($280 million attributable to Hess Corporation after income taxes and noncontrolling interests). This sale transaction included both upstream and midstream assets resulting in an after-tax gain of $314 million allocated to the E&P segment, and an after-tax loss of $34 million allocated to the Midstream segment. In November, we completed the sale of our interests in Equatorial Guinea for proceeds of $449 million, after normal closing adjustments, which resulted in a pre-tax gain of $486 million ($486 million after income taxes). In December, we completed the sale of our interests in the Valhall and Hod assets, offshore Norway for proceeds of $2,056 million, after normal closing adjustments, which resulted in a pre-tax loss of $857 million ($857 million after income taxes). This loss included the recognition of cumulative translation adjustments totaling $900 million in earnings that were previously reflected within *Accumulated Other Comprehensive Income (Loss)* in *Stockholders' Equity*. We also sold certain U.S. onshore assets for proceeds totaling approximately $194 million and recognized net pre-tax gains totaling $12 million ($12 million after income taxes).

Pre-tax income (loss) associated with our interests in Equatorial Guinea and Norway, excluding the financial statement impacts resulting from the asset sales in 2017, were as follows for the three years ended December 31:

	2019	2018	2017
		(In millions)	
Equatorial Guinea (a)	$ —	$ —	$ 69
Norway (b)	—	—	(55)
Income (Loss) from Continuing Operations Before Income Taxes	**$ —**	$ —	$ 14

(a) Pre-tax income for 2017 excludes the gain of $486 million related to sale of our assets in November 2017.
(b) Pre-tax loss for 2017 excludes the loss of $857 million related to sale of our assets in December 2017. In addition, the 2017 loss excludes a pre-tax impairment charge of $2,503 million associated with the disposition.

4. Inventories

Inventories at December 31 were as follows:

	2019	2018
	(In millions)	
Crude oil and natural gas liquids	**$ 92**	$ 74
Materials and supplies	**169**	171
Total Inventories	**$ 261**	$ 245

5. Property, Plant and Equipment

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

	2019	2018
	(In millions)	
Exploration and Production		
Unproved properties	**$ 168**	$ 394
Proved properties	**3,304**	3,124
Wells, equipment and related facilities	**28,404**	26,173
	31,876	29,691
Midstream	**3,904**	3,492
Corporate and Other	**40**	39
Total — at cost	**35,820**	33,222
Less: Reserves for depreciation, depletion, amortization and lease impairment	**19,006**	17,139
Property, Plant and Equipment — Net	**$ 16,814**	$ 16,083

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:

	2019	2018	2017
		(In millions)	
Balance at January 1	**$ 418**	$ 304	$ 597
Additions to capitalized exploratory well costs pending the determination of proved reserves	**224**	128	116
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(58)**	—	(165)
Capitalized exploratory well costs charged to expense	**—**	(14)	(268)
Dispositions and other	**—**	—	24
Balance at December 31	**$ 584**	$ 418	$ 304
Number of Wells at December 31	**31**	24	12

During the three years ended December 31, 2019, additions to capitalized exploratory well costs primarily related to drilling at the Stabroek Block, offshore Guyana. Other drilling activity included the Esox prospect in the Gulf of Mexico during 2019 and the Bunga prospect in Malaysia during 2018. Reclassifications to wells, facilities and equipment based on the determination of proved reserves in 2019 primarily related to the Stabroek Block, offshore Guyana, where the Liza Phase 2 development was sanctioned and the Esox discovery. In 2017, the Liza Phase 1 development was sanctioned.

Capitalized exploratory well costs included in the table above that were charged to expense include the following:

2018: In Canada, offshore Nova Scotia (Hess 50% participating interest), the operator, BP Canada, completed drilling of the Aspy exploration well, which did not encounter commercial quantities of hydrocarbons. As a result, we expensed well costs totaling $120 million of which $106 million was incurred and expensed in 2018.

2017: In Ghana, at the Hess operated offshore Deepwater Tano/Cape Three Points license (Hess 50% license interest), management determined in the fourth quarter of 2017 that we would not develop the previously discovered fields. As a result, we recorded a charge of $268 million to write-off previously capitalized exploration wells.

The preceding table excludes well costs incurred and expensed during 2019 of $49 million (2018: $151 million; 2017: $0 million).

Exploratory well costs capitalized for greater than one year following completion of drilling were $400 million at December 31, 2019, separated by year of completion as follows (in millions):

2018	$	157
2017		73
2016		—
2015		166
2014 and prior		4
	$	400

Guyana: Approximately 50% of the capitalized well costs in excess of one year relates to ten successful exploration wells where hydrocarbons were encountered on the Stabroek Block, offshore Guyana. The operator plans further appraisal drilling for certain fields and is conducting pre-development planning for additional phases of development beyond the two existing sanctioned phases of development.

Gulf of Mexico: Approximately 30% of the capitalized well costs in excess of one year relates to the appraisal of the northern portion of the Shenzi Field (Hess 28%) in the Gulf of Mexico, where hydrocarbons were encountered in the fourth quarter of 2015. Following exploration and appraisal drilling activities completed by the operator in prior years on adjacent blocks to the north of our Shenzi blocks, the operator commenced acquiring 3D seismic in 2019 for use in ongoing appraisal and development planning of the northern portion of the Shenzi Field.

JDA: Approximately 10% of the capitalized well costs in excess of one year relates to the JDA in the Gulf of Thailand (Hess 50%) 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: Approximately 10% of the capitalized well costs in excess of one year relates to North Malay Basin, offshore Peninsular Malaysia (Hess 50%), where hydrocarbons were encountered in five successful exploration wells. We are continuing with pre-development planning for future phases of field development.

6. Hess Midstream

Prior to December 16, 2019, the Midstream segment was primarily comprised of 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 March 1, 2019, HIP acquired Hess’s existing Bakken water services business for $225 million in cash. As a result of this transaction between entities under common control, we recorded an after-tax gain of $78 million in additional paid-in capital with an offsetting reduction to noncontrolling interest to reflect the adjustment to GIP’s noncontrolling interest in HIP. On March 22, 2019, HIP and Hess Midstream Partners acquired crude oil and gas gathering assets, and HIP acquired water gathering assets of Summit Midstream Partners LP’s Tioga Gathering System for aggregate cash consideration of approximately $90 million, with the potential for an additional $10 million of contingent payments in future periods subject to certain future performance metrics. On January 25, 2018, Hess Midstream Partners entered into a 50/50 joint venture with Targa Resources Corp. to construct a new 200 million standard cubic feet per day gas processing plant called Little Missouri 4. The plant, which is operated by Targa, was placed into service in the third quarter of 2019.

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 LP. 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, we 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 own 6% of the consolidated entity on an as-exchanged basis and Hess and GIP each own 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, or referred to as “Hess Corporation’s 47% consolidated ownership in Hess Midstream LP”.

At December 31, 2019, Hess Midstream liabilities totaling $1,941 million are on a nonrecourse basis to Hess Corporation, while Hess Midstream assets available to settle the obligations of Hess Midstream included Cash and cash equivalents totaling $3 million and Property, plant and equipment, net totaling $3,010 million. At December 31, 2018, HIP liabilities totaling $1,105 million were on a nonrecourse basis to Hess Corporation, while HIP assets available to settle the obligations of HIP included Cash and cash equivalents totaling $109 million and Property, plant and equipment, net totaling $2,664 million.

7. 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 on a straight-line basis 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. We recognize lease cost for short-term leases on a straight-line basis over the term of the lease. Some of our leases 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.

Operating and finance leases presented on the *Consolidated Balance Sheet* at December 31, 2019 were as follows:

	Operating Leases	Finance Leases
	(In millions)	
Right-of-use assets — net (a)	$ 447	$ 299
Lease obligations:		
Current	$ 182	$ 17
Long-term	353	238
Total lease obligations	$ 535	$ 255

(a) Finance lease ROU assets have a cost of $381 million and accumulated amortization of $82 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, 2019 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, as detailed in *Note 8, Debt*, 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 (Hess operated – 50%). The remaining lease term utilized in the lease obligation is 13.8 years.

Maturities of lease obligations at December 31, 2019 were as follows:

	Operating Leases	Finance Leases
	(In millions)	
2020	$ 200	$ 36
2021	72	36
2022	65	36
2023	64	36
2024	65	36
Remaining years	133	212
Total lease payments	599	392
Less: Imputed interest	(64)	(137)
Total lease obligations	$ 535	$ 255

The following information relates to the Operating and Finance leases recorded at December 31, 2019:

	Operating Leases	Finance Leases
Weighted average remaining lease term	5.4 years	13.8 years
Range of remaining lease terms	0.1 - 16.1 years	13.8 years
Weighted average discount rate	4.3%	7.9%

The components of lease costs for the year ended December 31, 2019 were as follows (in millions):

Operating lease cost	$ 414
Finance lease cost:	
Amortization of leased assets	43
Interest on lease obligations	21
Short-term lease cost (a)	164
Variable lease cost (b)	89
Sublease income (c)	(12)
Total lease cost (d)	$ 719

(a) Short-term lease cost is primarily attributable to equipment used in global exploration, development, and production activities. Future short-term lease costs will vary based on activity levels of our operated assets.
(b) Variable lease costs for the drilling rig leases 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.
(c) We sublease certain of our office space to third parties under our head lease.
(d) Prior to the adoption of ASC 842, we incurred total rental expense of $154 million in 2018 (2017: $123 million) and income from subleases of $8 million (2017: $10 million).

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 for the year ended December 31, 2019 was as follows:

	Operating Leases	Finance Leases
	(In millions)	
Cash paid for amounts included in the measurement of lease obligations:		
Operating cash flows (a)	$ 419	$ 21
Financing cash flows (a)	—	55
Noncash transactions:		
Leased assets recognized for new lease obligations incurred	14	—

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

8. Debt

Total debt at December 31 consisted of the following:

	2019	2018
	(In millions)	
Debt - Hess Corporation:		
Fixed-rate public notes:		
3.5% due 2024	**$ 298**	$ 298
4.3% due 2027	**992**	992
7.9% due 2029	**463**	463
7.3% due 2031	**628**	627
7.1% due 2033	**537**	537
6.0% due 2040	**741**	740
5.6% due 2041	**1,235**	1,234
5.8% due 2047	**494**	493
Total fixed-rate public notes	**5,388**	5,384
Capital lease obligations (a)	**—**	269
Financing obligations associated with floating production system (a)	**—**	40
Fair value adjustments - interest rate hedging	**1**	(2)
Total Debt - Hess Corporation	**$ 5,389**	$ 5,691
Debt - Midstream:		
Fixed-rate notes: 5.6% due 2026 - Hess Midstream Operations LP	**$ 787**	$ —
Fixed-rate notes: 5.1% due 2028 - Hess Midstream Operations LP	**540**	—
Fixed-rate notes: 5.6% due 2026 - HIP	**—**	787
Term loan A facility - Hess Midstream Operations LP	**394**	—
Term loan A facility - HIP	**—**	194
Revolving credit facility - Hess Midstream Operations LP	**32**	—
Total Debt - Midstream	**$ 1,753**	**$ 981**
Total Debt:		
Current maturities of long-term debt	**$ —**	$ 67
Long-term debt	**7,142**	6,605
Total Debt	**$ 7,142**	$ 6,672

(a) Upon adoption of ASC 842, Leases on January 1, 2019, capital lease and financing obligations previously included in Debt were reclassified to Finance leases.

At December 31, 2019, the maturity profile of total debt was as follows:

	Total	Hess Corporation	Midstream
		(In millions)	
2020	$ —	$ —	$ —
2021	10	—	10
2022	20	—	20
2023	30	—	30
2024	672	300	372
Thereafter	6,488	5,138	1,350
Total Borrowings	7,220	5,438	1,782
Less: Deferred issuance costs	(78)	(49)	(29)
Total Debt (excluding interest)	$ 7,142	$ 5,389	$ 1,753

Debt – Hess Corporation:

Fixed-rate public notes:

At December 31, 2019, Hess Corporation’s fixed-rate public notes had a gross principal amount of $5,438 million (2018: $5,438 million) and a weighted average interest rate of 5.9% (2018: 5.9%). Our long-term debt agreements, including the revolving credit facility, contain financial covenants that restrict the amount of total borrowings and secured debt. The most restrictive of these covenants allow us to borrow up to an additional $2,384 million of secured debt at December 31, 2019. Capitalized interest was $38 million in 2019 (2018: $20 million; 2017: $86 million).

In 2018, we paid $553 million to redeem $350 million principal amount of 8.125% notes due 2019 and to purchase other notes with a carrying value of $150 million. As a result, we recorded total losses on debt extinguishment of $53 million. Concurrent with the redemption of the 2019 notes, we terminated interest rate swaps with a notional amount of $350 million.

Capital lease:

In 2018, we entered into a sale and lease-back arrangement for an FSO to handle produced condensate at North Malay Basin, offshore Peninsular Malaysia (Hess operated – 50%). Pursuant to the sale agreement, we received total proceeds of approximately $260 million. No gain or loss was recognized from the sale transaction. The agreement is for 16 years with four consecutive twelve-month renewal options that may be exercised at our discretion. At December 31, 2018, the carrying value of the capital lease asset was $264 million and the carrying value of the capital lease obligation was $269 million, of which $15 million was included in *Current maturities of long-term debt* and $254 million was included in *Long-term debt* on our *Consolidated Balance Sheet*.

Credit facility:

In 2019, the Corporation entered into a new $3.5 billion revolving credit facility with a maturity date of May 15, 2023, which replaced the Corporation's previous revolving credit facility that was scheduled to mature on January 21, 2021. The new facility can be used for borrowings and letters of credit. Borrowings on the new facility will generally bear interest at 1.30% above LIBOR, though the interest rate is subject to adjustment if the Corporation's credit rating changes. The facility is subject to customary representations, warranties and covenants, including a financial covenant limiting the ratio of Total Consolidated Debt to Total Capitalization (as such terms are defined in the credit agreement for the facility) of the Corporation and its consolidated subsidiaries to 65%, and customary events of default. At December 31, 2019, Hess Corporation had no outstanding borrowings or letters of credit under this facility and was in compliance with this financial covenant.

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

	2019	2018
	(In millions)	
Committed lines (a)	**$ 54**	$ 29
Uncommitted lines (a)	**218**	255
Total	**$ 272**	$ 284

(a) At December 31, 2019, committed and uncommitted lines have expiration dates throughout 2020.

Debt - Midstream:

Senior unsecured notes:

In November 2017, HIP issued $800 million of 5.625% senior unsecured notes due in 2026. In December 2019, in connection with the acquisition of HIP and corporate restructuring described in *Note 6, Hess Midstream*, HESM Opco assumed $800 million of outstanding HIP senior notes in a par-for-par exchange. The senior notes are guaranteed by certain subsidiaries of HESM Opco.

In addition, in December 2019, HESM Opco issued $550 million of 5.125% senior unsecured notes due in 2028. The notes are guaranteed by HESM Opco's direct and indirect wholly owned material domestic subsidiaries. Proceeds of the new notes were used to finance the acquisition of HIP and repay outstanding borrowings under HIP's credit facilities.

Credit facilities:

Prior to the closing of the December 2019 transaction described in *Note 6, Hess Midstream*, HIP had a $600 million 5-year senior secured revolving credit facility and a $200 million senior secured Term Loan A facility, while Hess Midstream Partners LP had a $300 million 4-year senior secured syndicated revolving credit facility. In connection with the acquisition of HIP, both HIP and Hess Midstream Partners LP retired their existing senior secured revolving credit facilities and HESM Opco entered into a new 5-year senior secured syndicated revolving credit facility in the amount of $1.0 billion. HIP also retired its senior secured Term Loan A facility, which had borrowings of $190 million excluding deferred issuance costs, and HESM Opco entered into a fully drawn $400 million 5-year Term Loan A facility, receiving cash of $210 million at closing. The new revolving credit facility can be used for borrowings and letters of credit to fund HESM Opco's operating activities, capital expenditures, distributions and for other general corporate purposes. Borrowings under the 5-year Term Loan A facility will generally bear interest at LIBOR plus an applicable margin ranging from 1.55% to 2.50%, while the applicable margin for the 5-year syndicated revolving credit facility ranges from 1.275% to 2.000%. 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 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. The credit facilities are secured by first-priority perfected liens on substantially all the presently owned and after-acquired 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, 2019, borrowings of $32 million were drawn under HESM Opco's revolving credit facility, and borrowings of $400 million, excluding deferred issuance costs, were drawn under HESM Opco's Term Loan A facility. Borrowings under these credit facilities are non-recourse to Hess Corporation.

9. Asset Retirement Obligations

The following table describes changes to our asset retirement obligations:

	2019	2018
	(In millions)	
Balance at January 1	**$ 857**	$ 801
Liabilities incurred	**72**	68
Liabilities settled or disposed of	**(75)**	(46)
Accretion expense	**40**	37
Revisions of estimated liabilities	**129**	1
Foreign currency remeasurement	**1**	(4)
Balance at December 31	**$ 1,024**	$ 857
Total Asset Retirement Obligations at December 31:		
Current portion of asset retirement obligations	**$ 127**	$ 116
Long-term asset retirement obligations	**897**	741
Total at December 31	**$ 1,024**	$ 857

The liabilities incurred in 2019 primarily relate to operations in Guyana, the U.S. and Malaysia, while liabilities incurred in 2018 primarily relate to operations in the U.S. and UK as well as acquired participating interests. The liabilities settled or disposed of primarily reflect activity in the Gulf of Mexico and the Bakken in 2019, while activity in 2018 primarily relates to abandonment activity and an asset disposal onshore in the U.S. The revisions of estimated liabilities in 2019 reflect an acceleration of planned abandonment activity in the Gulf of Mexico and changes in service and equipment rates.

The fair value of 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*, was $178 million at December 31, 2019 (2018: $148 million).

10. 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. Additionally, we maintain an unfunded postretirement medical plan that provides health benefits to certain 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	
	2019	2018	2019	2018	2019	2018
	(In millions)					
Change in Benefit Obligation						
Balance at January 1,	**$ 2,492**	$ 2,765	**$ 216**	$ 249	**$ 59**	$ 87
Service cost	**33**	30	**11**	12	**2**	2
Interest cost	**82**	84	**7**	7	**2**	3
Actuarial (gains) loss (a)	**401**	(237)	**22**	(29)	**19**	(24)
Single premium annuity contract payment	**(249)**	—	**—**	—	**—**	—
Benefit payments (b)	**(113)**	(110)	**(14)**	(19)	**(7)**	(7)
Plan curtailments	**—**	(10)	**—**	(4)	**—**	(2)
Plan amendments	**—**	4	**—**	—	**—**	—
Foreign currency exchange rate changes	**21**	(34)	**—**	—	**—**	—
Balance at December 31, (c)	**2,667**	2,492	**242**	216	**75**	59
Change in Fair Value of Plan Assets						
Balance at January 1,	**$ 2,568**	$ 2,732	**$ —**	$ —	**$ —**	$ —
Actual return on plan assets	**462**	(77)	**—**	—	**—**	—
Employer contributions	**40**	59	**14**	19	**7**	7
Single premium annuity contract payment	**(249)**	—	**—**	—	**—**	—
Benefit payments (b)	**(113)**	(110)	**(14)**	(19)	**(7)**	(7)
Foreign currency exchange rate changes	**24**	(36)	**—**	—	**—**	—
Balance at December 31,	**2,732**	2,568	**—**	—	**—**	—
Funded Status (Plan assets greater (less) than benefit obligations) at December 31,	**$ 65**	$ 76	**$ (242)**	$ (216)	**$ (75)**	$ (59)
Unrecognized Net Actuarial (Gains) Losses	**$ 756**	$ 778	**$ 65**	$ 47	**$ (12)**	$ (32)

(a) Changes in discount rates resulted in actuarial losses of approximately $465 million in 2019 (2018: $235 million of actuarial gains from changes in discount rates).
(b) Benefit payments include lump-sum settlement payments of approximately $27 million in 2019 (2018: $32 million).
(c) At December 31, 2019, the accumulated benefit obligation for the funded and unfunded defined benefit pension plans was $2,580 million and $194 million, respectively (2018: $2,424 million and $171 million, respectively).

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

	Funded Pension Plans		Unfunded Pension Plan		Postretirement Medical Plan	
	2019	2018	2019	2018	2019	2018
	(In millions)					
Noncurrent assets	**$ 71**	$ 76	**$ —**	$ —	**$ —**	$ —
Current liabilities	**—**	—	**(32)**	(30)	**(8)**	(9)
Noncurrent liabilities	**(6)**	—	**(210)**	(186)	**(67)**	(50)
Pension assets / (accrued benefit liability)	**$ 65**	$ 76	**$ (242)**	$ (216)	**$ (75)**	$ (59)
Accumulated other comprehensive loss, pre-tax (a)	**$ 756**	$ 778	**$ 65**	$ 47	**$ (12)**	$ (32)

(a) The after-tax deficit reflected in Accumulated other comprehensive income (loss) was $601 million at December 31, 2019 (2018: $581 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		
	2019	2018	2017	2019	2018	2017
	(In millions)					
Service cost	**$ 44**	$ 42	$ 49	**$ 2**	$ 2	$ 4
Interest cost	**89**	91	102	**2**	3	3
Expected return on plan assets	**(180)**	(194)	(168)	**—**	—	—
Amortization of unrecognized net actuarial losses (gains)	**52**	39	58	**(1)**	(2)	—
Settlement loss	**93**	4	19	**—**	—	—
Curtailment gain	**—**	—	—	**—**	(2)	—
Net Periodic Benefit Cost (a)	**$ 98**	$ (18)	$ 60	**$ 3**	$ 1	$ 7

(a) Net non-service pension costs are included in Other, net in the Statement of Consolidated Income. In 2019, net non-service pension costs amounted to an expense of $55 million (2018: $61 million of income; 2017: $14 million of expense).

In 2019, the trust for the Hess Corporation Employees' Pension Plan (the "Plan") purchased a single premium annuity contract at a cost of approximately $250 million using assets of the Plan to settle and transfer certain of its obligations to a third party. The settlement transaction resulted in a noncash charge of $88 million to recognize unamortized pension actuarial losses that is included in *Other, net* in the *Statement of Consolidated Income*. In connection with this settlement transaction, as required under U.S. accounting standards, we remeasured the Plan, which resulted in a net increase in Plan liabilities of $239 million driven by a change in the weighted average discount rate used and an update to the fair value of Plan assets.

In 2020, we forecast pension service costs for our pension and postretirement medical plans to be approximately $55 million and net non-service pension costs of approximately $55 million of income, which is comprised of interest cost of approximately $75 million, amortization of unrecognized net actuarial losses of approximately $50 million, and estimated expected return on plan assets of approximately $180 million.

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:

	2019	2018	2017
Benefit Obligations:			
Discount rate	**2.9%**	3.9%	3.3%
Rate of compensation increase	**3.8%**	3.8%	4.5%
Net Periodic Benefit Cost:			
Discount rate			
Service cost	**3.9%**	3.9%	3.7%
Interest cost	**3.4%**	3.3%	3.7%
Expected return on plan assets	**7.1%**	7.2%	7.3%
Rate of compensation increase	**3.8%**	4.5%	4.6%

The actuarial assumptions used to determine Benefit obligations at December 31 for the postretirement medical plan were as follows:

	2019	2018	2017
Discount rate	**2.8%**	3.9%	3.2%
Initial health care trend rate	**6.5%**	6.9%	7.3%
Ultimate trend rate	**4.5%**	4.5%	4.5%
Year in which ultimate trend rate is reached	**2038**	2038	2038

The assumptions used to determine net periodic benefit cost for each year were established at the end of each previous year while the assumptions used to determine benefit obligations were established at each year-end. The net periodic benefit cost and the actuarial present value of benefit obligations are based on actuarial assumptions that are reviewed on an annual basis. The discount rate is developed based on a portfolio of high-quality, fixed income debt instruments with maturities that approximate the expected payment of plan obligations. Beginning in 2018, we elected to use a split discount rate approach for all of our retirement plans. This involves the continued use of a single weighted-average discount rate in the calculation of the projected benefit obligation, and separate discount rates for each projected benefit payment in the calculation of service cost and interest cost. In contrast, historically, a single weighted-average discount rate was used in both the calculation of the projected benefit obligation, and service cost and interest cost.

The overall expected return on plan assets is developed from the expected future returns for each asset category, weighted by the target allocation of pension assets to that asset category. The future expected return assumptions for individual asset categories are largely based on inputs from various investment experts regarding their future return expectations for particular asset categories.

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 for plan assets are 45% equity securities, 35% 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, 2019 and 2018 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 (d)	Total
			(In millions)		
December 31, 2019					
Cash and Short-Term Investment Funds	**$ 57**	**$ —**	**$ —**	**$ —**	**$ 57**
Equities:					
U.S. equities (domestic)	**638**	**—**	**—**	**—**	**638**
International equities (non-U.S.)	**80**	**37**	**—**	**302**	**419**
Global equities (domestic and non-U.S.)	**—**	**8**	**—**	**196**	**204**
Fixed Income:					
Treasury and government issued (a)	**—**	**210**	**—**	**—**	**210**
Government related (b)	**—**	**162**	**—**	**56**	**218**
Mortgage-backed securities (c)	**—**	**141**	**—**	**30**	**171**
Corporate	**—**	**293**	**—**	**82**	**375**
Other:					
Hedge funds	**—**	**—**	**—**	**65**	**65**
Private equity funds	**—**	**—**	**—**	**191**	**191**
Real estate funds	**27**	**—**	**—**	**157**	**184**
Total investments	**$ 802**	**$ 851**	**$ —**	**$ 1,079**	**$ 2,732**
December 31, 2018					
Cash and Short-Term Investment Funds	$ 3	$ 47	$ —	$ —	$ 50
Equities:					
U.S. equities (domestic)	654	—	—	—	654
International equities (non-U.S.)	92	29	—	288	409
Global equities (domestic and non-U.S.)	2	203	—	—	205
Fixed Income:					
Treasury and government issued (a)	—	240	—	—	240
Government related (b)	—	37	—	—	37
Mortgage-backed securities (c)	—	159	—	27	186
Corporate	—	272	—	31	303
Other:					
Hedge funds	—	—	—	135	135
Private equity funds	—	—	—	170	170
Real estate funds	49	—	—	111	160
Diversified commodities funds	—	19	—	—	19
Total investments	$ 800	$ 1,006	$ —	$ 762	$ 2,568

(a) *Includes securities issued* and guaranteed by U.S. and non-U.S. governments.
(b) *Primarily consists of securities issued by governmental agencies and municipalities.*
(c) *Comprised of U.S. residential and commercial mortgage-backed securities.*
(d) *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. In 2019, we elected to apply the NAV practical expedient to the plan's investments in non-exchange traded Real Estate Funds and, as such, have presented investments in Real Estate Funds that were previously categorized as Level 3 at December 31, 2018 totaling $61 million on a basis consistent with 2019.*

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 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, 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 of fixed income securities. Individual fixed income securities are generally priced based on evaluated prices from independent pricing services, which are monitored and provided by the third-party custodial firm responsible for safekeeping assets of the particular plan and are classified as Level 2. 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: We expect to contribute approximately $45 million to our funded pension plans in 2020.

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

2020	$	127
2021		126
2022		128
2023		130
2024		133
Years 2025 to 2029		674

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 $20 million in 2019 for contributions to these plans (2018: $19 million; 2017: $22 million).

11. Share-based Compensation

We have established and maintain long term incentive plans (LTIP) for the granting of restricted common shares (Restricted stock), PSUs and stock options to our employees. At December 31, 2019, the total number of authorized common stock under the LTIP was 51.5 million shares, of which we have 16.4 million shares available for issuance. Share-based compensation expense consisted of the following:

	2019	2018	2017
		(In millions)	
Restricted stock	**$ 53**	$ 40	$ 56
Stock options	**10**	10	9
Performance share units	**22**	22	21
Share-based compensation expense before income taxes	**$ 85**	$ 72	$ 86
Income tax benefit on share-based compensation expense	**$ —**	$ —	$ 1

Based on share-based compensation awards outstanding at December 31, 2019, unearned compensation expense, before income taxes, will be recognized in future years as follows (in millions): 2020: $53, 2021: $29 and 2022: $4.

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 are 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 2019:

	Shares of Restricted Common Stock	Weighted - Average Price on Date of Grant
	(In thousands, except per share amounts)	
Outstanding at January 1, 2019	2,881	$ 48.70
Granted	965	56.87
Vested (a)	(1,742)	47.35
Forfeited	(90)	52.67
Outstanding at December 31, 2019	2,014	$ 53.61

(a) In 2019, restricted stock with fair values of $102 million were vested (2018: $54 million; 2017: $37 million).

PSUs:

PSUs generally vest three years from the date of grant and are valued using a Monte Carlo simulation on the date of grant. 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 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. The following is a summary of PSU activity in 2019:

	Performance Share Units	Weighted - Average Fair Value on Date of Grant
	(In thousands, except per share amounts)	
Outstanding at January 1, 2019	1,063	$ 53.98
Granted	269	68.87
Vested (a)	(391)	51.00
Forfeited	(12)	52.05
Outstanding at December 31, 2019	929	$ 59.57

(a) In 2019, PSU's with fair value of $16 million were vested (2018: $9 million; 2017: $10 million).

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

	2019	2018	2017
Risk free interest rate	**2.48%**	2.39%	1.55%
Stock price volatility	**0.369**	0.400	0.387
Contractual term in years	**3.0**	3.0	3.0
Grant date price of Hess common stock	**$ 56.74**	$ 48.48	$ 51.03

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 2019:

	Number of options (In thousands)	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term
Outstanding at January 1, 2019	5,170	$ 61.91	4.3 years
Granted	527	56.74	
Exercised	(744)	54.23	
Forfeited	(652)	57.69	
Outstanding at December 31, 2019	4,301	$ 63.24	4.8 years

At December 31, 2019, there were 4.3 million outstanding stock options (3.1 million exercisable) with a weighted average remaining contractual life of 4.8 years (3.4 years for exercisable options) and an aggregated intrinsic value of $39 million ($22 million for exercisable options).

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

	2019	2018	2017
Risk free interest rate	**2.55%**	2.74%	2.17%
Stock price volatility	**0.359**	0.322	0.333
Dividend yield	**1.76%**	2.06%	1.96%
Expected life in years	**6.0**	6.0	6.0
Weighted average fair value per option granted	**$ 18.08**	$ 13.69	$ 14.51

In estimating the fair value of PSUs and stock options, the risk-free interest rate is based on the vesting period 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.

12. Exit and Disposal Costs

In 2018, we incurred severance expense of $38 million (2017: $18 million) associated with asset sales and cost savings initiatives in response to low crude oil prices. In 2019, we paid accrued severance costs of $4 million (2018: $40 million; 2017: $48 million).

13. Impairment

In the third quarter of 2017, we recognized a pre-tax charge of $2,503 million ($550 million after income taxes) to impair the carrying value of our interests in Norway based on an anticipated sale of the asset, which closed in the fourth quarter of 2017. See *Note 3*, *Dispositions*.

In the fourth quarter of 2017, we recognized pre-tax impairment charges to reduce the carrying value of our interests in the Stampede Field by $1,095 million ($1,095 million after income taxes), and the Tubular Bells Field by $605 million ($605 million after income taxes) primarily as a result of a lower long-term crude oil price outlook. The Stampede Field had significant capitalized exploration and appraisal costs that were incurred on a 100% working interest basis on the Pony discovery prior to unitizing into the Stampede project. These impairment charges were based on a total fair value estimate of approximately $1.1 billion that was determined using internal projected discounted cash flows. The determination of projected discounted cash flows depended on estimates of oil and gas reserves, future prices, operating costs, capital expenditures, discount rate and timing of future net cash flows. Each of the valuation methods used in the determination of the impairment charges above represent Level 3 fair value measurements.

14. Income Taxes

The provision (benefit) for income taxes consisted of:

	2019	2018	2017
		(In millions)	
United States			
Federal			
Current	**$ (1)**	$ 1	$ (23)
Deferred taxes and other accruals	**72**	(74)	(6)
State	**16**	(45)	—
	87	(118)	(29)
Foreign			
Current (a)	**447**	455	179
Deferred taxes and other accruals	**(73)**	(2)	(1,987)
	374	453	(1,808)
Total Provision (Benefit) For Income Taxes	**$ 461**	$ 335	$ (1,837)

(a) *Primarily comprised of Libya in 2019, 2018 and 2017.*

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

	2019	2018	2017
		(In millions)	
United States (a)	**$ (338)**	$ (219)	$ (2,784)
Foreign	**559**	439	(2,994)
Total Income (Loss) Before Income Taxes	**$ 221**	$ 220	$ (5,778)

(a) *Includes substantially all of our interest expense, corporate expense and the results of commodity hedging activities.*

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

	2019	2018	2017
U.S. statutory rate	**21.0 %**	21.0 %	35.0 %
Effect of foreign operations (a)	**142.9**	141.2	17.4
State income taxes, net of Federal income tax	**5.8**	(18.9)	—
Change in enacted tax laws (b)	**—**	—	(23.6)
Valuation allowance adjustment with tax law change (b)	**—**	—	23.6
Rate differential on U.S. loss	**—**	—	(4.1)
Gains on asset sales, net	**—**	—	(2.2)
Valuation allowance on current year operations	**41.8**	55.2	(14.9)
Valuation allowance against previously benefited deferred tax assets	**—**	—	0.1
Release valuation allowance against previously unbenefited deferred tax assets	**(24.5)**	—	—
Noncontrolling interests in Midstream	**(16.0)**	(15.9)	0.8
Intraperiod allocation	**33.7**	(37.3)	—
Equity and executive compensation	**2.2**	7.4	(0.3)
Other	**1.2**	(0.3)	—
Total	**208.1 %**	152.4 %	31.8 %

(a) *The variance in effective income tax rates attributable to the effect of foreign operations primarily resulted from the mix of income among high, primarily Libya, and low tax rate jurisdictions.*
(b) *The enactment of the U.S. Tax Cuts and Jobs Act provided for a decrease in the corporate tax rate to 21% from 35% and a change to a territorial tax regime, resulting in a net $1,336 million reduction to our U.S. net deferred tax asset at December 31, 2017, with a corresponding reduction in the previously established U.S. valuation allowance.*

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

	2019	2018
	(In millions)	
Deferred Tax Liabilities		
Property, plant and equipment and investments	**$ (1,318)**	$ (853)
Other	**(45)**	(77)
Total Deferred Tax Liabilities	**(1,363)**	(930)
Deferred Tax Assets		
Net operating loss carryforwards	**4,733**	4,239
Tax credit carryforwards	**66**	134
Property, plant and equipment and investments	**206**	416
Accrued compensation, deferred credits and other liabilities	**179**	232
Asset retirement obligations	**261**	225
Other	**317**	161
Total Deferred Tax Assets	**5,762**	5,407
Valuation allowances (a)	**(4,734)**	(4,877)
Total deferred tax assets, net of valuation allowances	**1,028**	530
Net Deferred Tax Assets (Liabilities)	**$ (335)**	$ (400)

(a) In 2019, the valuation allowance decreased by $143 million (2018: decrease of $322 million; 2017: decrease of $251 million).

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

	2019	2018
	(In millions)	
Deferred income taxes (long-term asset)	**$ 80**	$ 21
Deferred income taxes (long-term liability)	**(415)**	(421)
Net Deferred Tax Assets (Liabilities)	**$ (335)**	$ (400)

At December 31, 2019, we have recognized a gross deferred tax asset related to net operating loss carryforwards of $4,733 million before application of valuation allowances. The deferred tax asset is comprised of $1,447 million attributable to foreign net operating losses which begin to expire in 2025, $2,746 million attributable to U.S. Federal operating losses which begin to expire in 2034, and $540 million attributable to losses in various U.S. states which begin to expire in 2020. The deferred tax asset attributable to foreign net operating losses, net of valuation allowances, is $110 million. A full valuation allowance is established against the deferred tax asset attributable to U.S. Federal and state net operating losses. At December 31, 2019, we have U.S. Federal, state and foreign alternative minimum tax credit carryforwards of $49 million, which can be carried forward indefinitely, and approximately $15 million of other business credit carryforwards. The deferred tax asset attributable to these credits, net of valuation allowances was not significant. A full valuation allowance is established against our foreign tax credit carryforwards of $3 million, which begin to expire in 2021.

At December 31, 2019, the Balance Sheet reflects a $4,734 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., Denmark (hydrocarbon tax only), Malaysia, and Guyana (until December 2019). 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. The cumulative loss incurred over the three-year period ending December 31, 2019 constitutes significant objective negative evidence. Such objective negative evidence limits our ability to consider subjective positive evidence, such as our projections of future taxable income, resulting in the recognition of a valuation allowance against the net deferred tax assets for these jurisdictions. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income change or if objective negative evidence in the form of cumulative losses is no longer present and additional weight can be given to subjective evidence. At December 31, 2019 the valuation allowance established against the net deferred tax asset in Guyana for the Stabroek Block was released as a result of the positive evidence from first production in December 2019, and the significant forecasted pre-tax income from operations. The cumulative pre-tax losses in Guyana were driven by pre-production activities.

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

	2019	2018	2017
		(In millions)	
Balance at January 1	**$ 168**	$ 205	$ 424
Additions based on tax positions taken in the current year	**2**	19	14
Additions based on tax positions of prior years	**1**	36	4
Reductions based on tax positions of prior years	**(1)**	(78)	(147)
Reductions due to settlements with taxing authorities	**—**	(10)	(85)
Reductions due to lapses in statutes of limitation	**(2)**	(4)	(5)
Balance at December 31	**$ 168**	$ 168	$ 205

The December 31, 2019 balance of unrecognized tax benefits includes $7 million that, if recognized, would impact our effective income tax rate. Over the next 12 months, it is reasonably possible that the total amount of unrecognized tax benefits could decrease between $4 million and $11 million due to settlements with taxing authorities or other resolutions, as well as lapses in statutes of limitation. At December 31, 2019, our accrued interest and penalties related to unrecognized tax benefits is $7 million (2018: $3 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 2011.

15. Outstanding and Weighted Average Common Shares

The Net income (loss) and weighted average number of common shares used in basic and diluted earnings per share computation were as follows:

	2019	2018	2017
		(In millions except per share amounts)	
Net Income (Loss) Attributable to Hess Corporation Common Stockholders:			
Net income (loss)	**$ (240)**	$ (115)	$ (3,941)
Less: Net income (loss) attributable to noncontrolling interests	**168**	167	133
Less: Preferred stock dividends	**4**	46	46
Net income (loss) attributable to Hess Corporation Common Stockholders	**$ (412)**	$ (328)	$ (4,120)
Weighted Average Number of Common Shares Outstanding:			
Basic	**301.2**	298.2	314.1
Effect of dilutive securities			
Restricted common stock	**—**	—	—
Stock options	**—**	—	—
Performance share units	**—**	—	—
Mandatory convertible preferred stock	**—**	—	—
Diluted	**301.2**	298.2	314.1
Net Income (Loss) Attributable to Hess Corporation per Common Share:			
Basic	**$ (1.37)**	$ (1.10)	$ (13.12)
Diluted	**$ (1.37)**	$ (1.10)	$ (13.12)
Antidilutive shares excluded from the computation of diluted shares:			
Restricted common stock	**2.2**	2.9	3.3
Stock options	**4.7**	5.5	6.4
Performance share units	**1.7**	1.1	0.6
Common shares from conversion of preferred stock	**—**	12.7	12.8

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

	2019	2018	2017
		(In millions)	
Balance at January 1	**291.4**	315.1	316.5
Conversion of preferred stock	**11.6**	—	—
Activity related to restricted stock awards, net	**0.9**	0.8	0.8
Stock options exercised	**0.7**	0.6	0.2
PSU vested	**0.3**	0.1	0.2
Shares repurchased	**—**	(25.2)	(2.6)
Balance at December 31	**304.9**	291.4	315.1

Common and Preferred Stock Issuance:

In February 2016, we issued 28,750,000 shares of common stock and depositary shares representing 575,000 shares of 8% Series A Mandatory Convertible Preferred Stock (Preferred Stock), par value $1 per share, with a liquidation preference of $1,000 per share, for total net proceeds of approximately $1.6 billion after deducting underwriting discounts, commissions, and offering expenses. The dividends on the Preferred Stock were payable on a cumulative basis. Unless converted earlier, each share of Preferred Stock would automatically convert into between 21.822 shares and 25.642 shares of our common stock based on the volume weighted average share price (“VWAP”) over a period of twenty-consecutive trading days ending January 28, 2019, subject to anti-dilution adjustments.

We also entered into capped call transactions on 12.55 million covered shares that were expected generally to reduce the potential dilution to our common stock upon conversion of the Preferred Stock if the VWAP for any individual day during the period of twenty consecutive trading days ending January 28, 2019 exceeded $45.83 per share, subject to anti-dilution adjustments.

On January 31, 2019, the Preferred Stock automatically converted into shares of common stock at a rate of 21.822 shares of common stock per share of Preferred Stock. In total, the Preferred Stock was converted into approximately 12.5 million shares of common stock and the Company received approximately 0.9 million shares of common stock upon settlement of the capped call transactions. As a result, the net number of common shares issued by the Company upon conversion of the Preferred Stock was approximately 11.6 million shares.

Common Stock Repurchase Plan:

In 2018, we repurchased 25.2 million shares of our common stock (2017: 2.6 million shares) for $1,380 million (2017: $120 million), at an average cost per share of $54.85 (2017: $45.67). At December 31, 2019, we are authorized, but not required, to purchase additional common stock up to a value of $650 million.

Common stock dividends:

In 2019, 2018 and 2017, cash dividends declared on common stock totaled $1.00 per share ($0.25 per quarter).

16. Supplementary Cash Flow Information

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

	2019	2018	2017
		(In millions)	
Cash Flows From Operating Activities			
Interest paid	**$ (380)**	$ (394)	$ (314)
Net income taxes (paid) refunded	**(417)**	(463)	(210)
Cash Flows From Investing Activities			
Additions to property, plant and equipment - E&P:			
Capital expenditures incurred - E&P	**$ (2,576)**	$ (1,909)	$ (1,852)
Increase (decrease) in related liabilities	**143**	55	64
Additions to property, plant and equipment - E&P	**$ (2,433)**	$ (1,854)	$ (1,788)
Additions to property, plant and equipment - Midstream:			
Capital expenditures incurred - Midstream	**$ (416)**	$ (271)	$ (121)
Increase (decrease) in related liabilities	**20**	28	(28)
Additions to property, plant and equipment - Midstream	**$ (396)**	$ (243)	$ (149)

In December 2019, as part of HESM Opco's acquisition of HIP (see *Note 6, Hess Midstream*), HESM Opco assumed $800 million of outstanding HIP notes (see *Note 8, Debt*).

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 methyl tertiary butyl ether (MTBE) in gasoline. A series of similar lawsuits, many involving water utilities or governmental entities, were filed in jurisdictions across the U.S. 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 three remaining active cases, filed by Pennsylvania, Rhode Island, 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 September 2016, the State of Rhode Island also filed a lawsuit alleging that we and other major oil companies damaged the groundwater in Rhode Island by introducing thereto gasoline with MTBE. The suit filed in Rhode Island is proceeding in Federal court. 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 September 2003, we received a directive from the New Jersey Department of Environmental Protection (NJDEP) to remediate contamination in the sediments of the Lower Passaic River. The NJDEP is also seeking natural resource damages. The directive, insofar as it affects us, relates to alleged releases from a petroleum bulk storage terminal in Newark, New Jersey we previously owned. We and over 70 companies entered into an Administrative Order on Consent with the Environmental Protection Agency (EPA) to study the same contamination; this work remains ongoing. We and other parties settled a cost recovery claim by the State of New Jersey and agreed with the EPA to fund remediation of a portion of the site. On March 4, 2016, the EPA issued a Record of Decision (ROD) in respect of the lower eight miles of the Lower Passaic River, selecting a remedy that includes bank-to-bank dredging at an estimated cost of $1.38 billion. The ROD does not address the upper nine miles of the Lower Passaic River or the Newark Bay, which may require additional remedial action. In addition, the Federal trustees for natural resources have begun a separate assessment of damages to natural resources in the Passaic River. Given that the EPA has not selected a remedy for the entirety of the Lower Passaic River or the Newark Bay, total remedial costs cannot be reliably estimated at this time. Based on currently known facts and circumstances, we do not believe that this matter will result in a significant liability to us because our former terminal did not store or use contaminants which are of concern in the river sediments and could not have contributed contamination along the river's length. Further, there are numerous other parties who we expect will bear the cost of remediation and damages.

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 is anticipated to begin in the fourth quarter of 2020. The costs will continue to be allocated amongst the parties, as they were for the Remedial Design.

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. The ultimate impact of these 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, but is not expected to be material.

From time to time, we are involved in other judicial and administrative proceedings, including proceedings relating to other environmental matters. 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, 2019, which are not included elsewhere within these *Consolidated Financial Statements*:

		Payments Due by Period			
	Total	2020	2021 and 2022	2023 and 2024	Thereafter
	(In millions)				
Capital expenditures	$ 1,743	$ 913	$ 755	$ 75	$ —
Operating expenses	190	158	20	9	3
Transportation and related contracts	1,009	231	424	246	108

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, 2019 were primarily in the United States (U.S.), Denmark, the JDA and Malaysia, and from divested assets, including Equatorial Guinea (until November 2017) and Norway (until December 2017). The Midstream operating segment provides fee-based services including crude oil and natural gas gathering, processing of natural gas and the fractionation of NGL, transportation of crude oil by rail car, terminaling and loading 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
2019					
Sales and Other Operating Revenues - Third parties	**$ 6,495**	**$ —**	**$ —**	**$ —**	**$ 6,495**
Intersegment Revenues	**—**	**848**	**—**	**(848)**	**—**
Sales and Other Operating Revenues	**$ 6,495**	**$ 848**	**$ —**	**$ (848)**	**$ 6,495**
Net Income (Loss) Attributable to Hess Corporation	**$ 53**	**$ 144**	**$ (605)**	**$ —**	**$ (408)**
Interest Expense	**—**	**63**	**317**	**—**	**380**
Depreciation, Depletion and Amortization	**1,977**	**142**	**3**	**—**	**2,122**
Provision (Benefit) for Income Taxes (a)	**375**	**—**	**86**	**—**	**461**
Investment in Affiliates	**114**	**108**	**—**	**—**	**222**
Identifiable Assets	**16,790**	**3,499**	**1,493**	**—**	**21,782**
Capital Expenditures	**2,576**	**416**	**—**	**—**	**2,992**
2018					
Sales and Other Operating Revenues - Third parties	$ 6,323	$ —	$ —	$ —	$ 6,323
Intersegment Revenues	—	713	—	(713)	—
Sales and Other Operating Revenues	$ 6,323	$ 713	$ —	$ (713)	$ 6,323
Net Income (Loss) Attributable to Hess Corporation	$ 51	$ 120	$ (453)	$ —	$ (282)
Interest Expense	—	60	339	—	399
Depreciation, Depletion and Amortization	1,748	127	8	—	1,883
Provision (Benefit) for Income Taxes (a)	391	38	(94)	—	335
Investment in Affiliates	126	67	—	—	193
Identifiable Assets	16,109	3,285	2,039	—	21,433
Capital Expenditures	1,909	271	—	—	2,180
2017					
Sales and Other Operating Revenues - Third parties	$ 5,460	$ 6	$ —	$ —	$ 5,466
Intersegment Revenues	—	611	—	(611)	—
Sales and Other Operating Revenues	$ 5,460	$ 617	$ —	$ (611)	$ 5,466
Net Income (Loss) Attributable to Hess Corporation	$ (3,653)	$ 42	$ (463)	$ —	$ (4,074)
Interest Expense	—	26	299	—	325
Depreciation, Depletion and Amortization	2,736	123	24	—	2,883
Impairment	4,203	—	—	—	4,203
Provision (Benefit) for Income Taxes (a)	(1,842)	31	(26)	—	(1,837)
Capital Expenditures	1,852	121	—	—	1,973

(a) Commencing January 1, 2019, management changed its measurement of segment earnings to reflect income taxes on a post U.S. tax consolidation and valuation allowance assessment basis. In 2018 and 2017, the provision for income taxes in the Midstream segment was presented before consolidating its operations with other U.S. activities of the Corporation and prior to evaluating realizability of net U.S. deferred taxes. An offsetting impact was presented in the E&P segment. If 2018 and 2017 segment results were prepared on a basis consistent with 2019, Midstream segment net income attributable to Hess Corporation would have been $158 million and $73 million, respectively, and E&P net income (loss) attributable to Hess Corporation would have been income of $13 million and a loss of $3,684 million, respectively.

The following table presents financial information by major geographic area:

	United States	Europe	Africa	Asia and Other Countries	Corporate, Interest and other	Total
			(In millions)			
2019						
Sales and Other Operating Revenues	**$ 5,043**	**$ 139**	**$ 551**	**$ 762**	**$ —**	**$ 6,495**
Net Income (Loss) Attributable to Hess Corporation	**15**	**2**	**36**	**144**	**(605)**	**(408)**
Depreciation, Depletion and Amortization	**1,631**	**53**	**21**	**414**	**3**	**2,122**
Provision (Benefit) for Income Taxes	**—**	**1**	**425**	**(51)**	**86**	**461**
Identifiable Assets	**14,234**	**1,070**	**399**	**4,586**	**1,493**	**21,782**
Property, Plant and Equipment (Net)	**12,182**	**871**	**350**	**3,399**	**12**	**16,814**
Capital Expenditures	**2,094**	**40**	**15**	**843**	**—**	**2,992**
2018						
Sales and Other Operating Revenues	$ 4,842	$ 164	$ 548	$ 769	$ —	$ 6,323
Net Income (Loss) Attributable to Hess Corporation	131	42	36	(38)	(453)	(282)
Depreciation, Depletion and Amortization	1,424	37	19	395	8	1,883
Provision (Benefit) for Income Taxes	(25)	15	430	9	(94)	335
Identifiable Assets	13,250	1,033	395	4,716	2,039	21,433
Property, Plant and Equipment (Net)	11,653	906	355	3,154	15	16,083
Capital Expenditures	1,543	8	9	620	—	2,180
2017						
Sales and Other Operating Revenues	$ 3,692	$ 629	$ 675	$ 470	$ —	$ 5,466
Net Income (Loss) Attributable to Hess Corporation	(2,433)	(1,383)	259	(54)	(463)	(4,074)
Depreciation, Depletion and Amortization	1,942	381	263	273	24	2,883
Impairment	1,700	2,503	—	—	—	4,203
Provision (Benefit) for Income Taxes	—	(1,999)	197	(9)	(26)	(1,837)
Capital Expenditures	1,387	141	30	415	—	1,973

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 by reducing our exposure to foreign currency or interest rate movements. Generally, futures, swaps or option strategies may be used to fix the forward selling price of a portion of our crude oil or natural gas production. Forward contracts 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, 2019, these forward contracts relate to the British Pound and the Danish Krone. 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, 2019	December 31, 2018
	(In millions)	
Commodity - crude oil (millions of barrels)	54.9	34.7
Foreign exchange	$ 90	$ 16
Interest rate swaps	$ 100	$ 100

For calendar year 2020 we have West Texas Intermediate (WTI) put options with an average monthly floor price of $55 per barrel for 130,000 bopd, and Brent put options with an average monthly floor price of $60 per barrel for 20,000 bopd.

The table below reflects the gross and net fair values of risk management derivative instruments and their respective financial statement caption in the *Consolidated Balance Sheet*:

	Assets	Liabilities
	(In millions)	
December 31, 2019		
Derivative Contracts Designated as Hedging Instruments:		
Commodity - Other current assets	$ 125	$ —
Interest rate - Other assets (noncurrent)	1	—
Total derivative contracts designated as hedging instruments	126	—
Derivative Contracts Not Designated as Hedging Instruments:		
Foreign exchange	—	(1)
Total derivative contracts not designated as hedging instruments	—	(1)
Gross fair value of derivative contracts	126	(1)
Master netting arrangements	—	—
Net Fair Value of Derivative Contracts	$ 126	$ (1)
December 31, 2018		
Derivative Contracts Designated as Hedging Instruments:		
Commodity - Other current assets	$ 484	$ —
Interest rate - Other liabilities and deferred credits (noncurrent)	—	(2)
Total derivative contracts designated as hedging instruments	484	(2)
Gross fair value of derivative contracts	484	(2)
Master netting arrangements	—	—
Net Fair Value of Derivative Contracts	$ 484	$ (2)

All fair values above are based on Level 2 inputs.

Impact on statement of consolidated income from derivative contracts designated as hedging instruments:

Crude oil derivatives: In 2019, crude oil price hedging contracts increased Sales and other operating revenues by $1 million (2018: decrease of $161 million; 2017: decrease of $34 million). At December 31, 2019, pre-tax deferred losses in *Accumulated other comprehensive income (loss)* related to outstanding crude oil price hedging contracts were $98 million, of which all will be reclassified into earnings during the next 12 months as the hedged crude oil sales are recognized in earnings.

Interest rate swaps designated as fair value hedges: At December 31, 2019, we had interest rate swaps with gross notional amounts of $100 million (2018: $100 million), which were designated as fair value hedges and relate to debt where we have converted interest payments on certain long-term debt from fixed to floating rates. Changes in the fair value of interest rate swaps and the hedged fixed-rate debt are recorded in *Interest expense* in the *Statement of Consolidated Income*. In 2019, the change in fair value of interest rate swaps was a decrease in the derivative liability of $3 million (2018: $1 million increase in liability; 2017: $4 million increase in liability) with a corresponding adjustment in the carrying value of the hedged fixed-rate debt. During 2018, we terminated interest rate swaps with a gross notional amount of $350 million and paid $3 million.

Impact on statement of consolidated income from derivative contracts not designated as hedging instruments:

Crude oil collars: In 2018, noncash adjustments to de-designated crude oil price hedging contracts decreased Sales and other operating revenues by $22 million (2017: decrease of $25 million).

Foreign exchange: Total foreign exchange gains and losses were a gain of $3 million in 2019 (2018: loss of $5 million; 2017: gain of $15 million) and are reported in *Other, net* in Revenues and non-operating income in the *Statement of Consolidated Income.* A component of foreign exchange gains or losses is the result of foreign exchange derivative contracts that are not designated as hedges, which amounted to a loss of $2 million in 2019 (2018: loss of $2 million; 2017: gain of $3 million).

In 2017, after-tax foreign currency translation adjustments included in the *Statement of Consolidated Comprehensive Income* amounted to gains of $144 million. In addition, $900 million of cumulative currency translation losses were recognized in earnings as a result of the sale of our assets in Norway. See *Note 3, Dispositions*.

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, 2019, our Accounts receivable were concentrated with the following counterparty industry segments: Integrated companies — 41%, Independent E&P companies — 26%, Refining and marketing companies — 14%, National oil companies — 8%, Storage and transportation companies — 5%, 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, 2019, we had outstanding letters of credit totaling $272 million (2018: $284 million).

Fair Value Measurement: At December 31, 2019, our total long-term debt, which was substantially comprised of fixed rate debt instruments, had a carrying value of $7,142 million and a fair value of $8,242 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, 2019 and December 31, 2018.

20. Subsequent Event

In January 2020, the operator, Kosmos Energy Ltd, completed drilling of the Oldfield-1 exploration well in the Gulf of Mexico. The well did not encounter commercial quantities of hydrocarbons and 2019 results include $15 million in exploration expense for well costs incurred through December 31, 2019. We estimate approximately $15 million of exploration expense will be recognized in the first quarter of 2020 for well costs incurred after December 31, 2019.

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.

During the three-year period ended December 31, 2019, we produced crude oil, NGL and natural gas principally in the United States (U.S.), Europe (Denmark and Norway until December 2017), Africa (Libya and Equatorial Guinea until November 2017) and Asia and Other (primarily the Malaysia/Thailand Joint Development Area (JDA) and Malaysia). Exploration and/or development activities were also conducted, or are planned, in certain of these producing areas as well as offshore Guyana, Suriname and Canada. See *Note 3, Dispositions* in the *Notes to Consolidated Financial Statements*.

Costs Incurred in Oil and Gas Producing Activities

For the Years Ended December 31	Total	United States	Europe	Africa	Asia and Other
			(In millions)		
2019					
Property acquisitions					
Unproved	**$ 26**	**$ 26**	**$ —**	**$ —**	**$ —**
Proved	**—**	**—**	**—**	**—**	**—**
Exploration	**455**	**174**	**25**	**—**	**256**
Production and development capital expenditures (a)	**2,463**	**1,735**	**14**	**15**	**699**
2018					
Property acquisitions					
Unproved	$ 51	$ 43	$ —	$ —	$ 8
Proved	43	43	—	—	—
Exploration	442	111	—	—	331
Production and development capital expenditures (a)	1,577	1,239	(7)	9	336
2017					
Property acquisitions					
Unproved	$ 46	$ 46	$ —	$ —	$ —
Proved	—	—	—	—	—
Exploration	322	94	1	—	227
Production and development capital expenditures (a)	1,687	1,160	146	40	341

(a) *Includes an increase of $201 million for asset retirement obligations related to net accruals and revisions in 2019 (2018: $44 million increase; 2017: $8 million increase).*

Capitalized Costs Relating to Oil and Gas Producing Activities

	At December 31, 2019	At December 31, 2018
	(In millions)	
Unproved properties	**$ 168**	$ 394
Proved properties	**3,304**	3,124
Wells, equipment and related facilities	**28,404**	26,173
Total costs	**31,876**	29,691
Less: Reserve for depreciation, depletion, amortization and lease impairment	**18,084**	16,361
Net Capitalized Costs	**$ 13,792**	$ 13,330

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, interest expense and non-operating income. 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	Europe	Africa	Asia and Other
			(In millions)		
2019					
Sales and Other Operating Revenues	**$ 4,719**	**$ 3,361**	**$ 139**	**$ 460**	**$ 759**
Costs and Expenses					
Operating costs and expenses	**971**	**693**	**68**	**33**	**177**
Production and severance taxes	**184**	**176**	**—**	**—**	**8**
Midstream tariffs	**722**	**722**	**—**	**—**	**—**
Exploration expenses, including dry holes and lease impairment	**233**	**144**	**26**	**—**	**63**
General and administrative expenses	**204**	**176**	**23**	**—**	**5**
Depreciation, depletion and amortization	**1,977**	**1,489**	**53**	**21**	**414**
Total Costs and Expenses	**4,291**	**3,400**	**170**	**54**	**667**
Results of Operations Before Income Taxes	**428**	**(39)**	**(31)**	**406**	**92**
Provision (benefit) for income taxes	**325**	**—**	**1**	**372**	**(48)**
Results of Operations	**$ 103**	**$ (39)**	**$ (32)**	**$ 34**	**$ 140**
2018					
Sales and Other Operating Revenues	$ 4,515	$ 3,141	$ 164	$ 455	$ 755
Costs and Expenses					
Operating costs and expenses	941	697	71	32	141
Production and severance taxes	171	165	—	—	6
Midstream tariffs	648	648	—	—	—
Exploration expenses, including dry holes and lease impairment	362	119	—	1	242
General and administrative expenses	258	230	22	—	6
Depreciation, depletion and amortization	1,748	1,297	37	19	395
Total Costs and Expenses	4,128	3,156	130	52	790
Results of Operations Before Income Taxes	387	(15)	34	403	(35)
Provision (benefit) for income taxes	337	(63)	14	376	10
Results of Operations	$ 50	$ 48	$ 20	$ 27	$ (45)
2017					
Sales and Other Operating Revenues	$ 4,128	$ 2,335	$ 628	$ 700	$ 465
Costs and Expenses					
Operating costs and expenses	1,250	652	275	186	137
Production and severance taxes	119	116	—	1	2
Midstream tariffs	543	543	—	—	—
Exploration expenses, including dry holes and lease impairment	507	106	1	280	120
General and administrative expenses	225	208	10	4	3
Depreciation, depletion and amortization	2,736	1,819	381	263	273
Impairment	4,203	1,700	2,503	—	—
Total Costs and Expenses	9,583	5,144	3,170	734	535
Results of Operations Before Income Taxes	(5,455)	(2,809)	(2,542)	(34)	(70)
Provision (benefit) for income taxes	(1,873)	(47)	(2,014)	197	(9)
Results of Operations	$ (3,582)	$ (2,762)	$ (528)	$ (231)	$ (61)

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 February 19, 2007)." 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. 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 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 *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 92 through 97). 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 2019 was Mr. Kenneth Kosco, Senior Manager, Global Reserves. Mr. Kosco is a member of the Society of Petroleum Engineers and has over 30 years of experience in the oil and gas industry with a BS 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. Mr. Kosco is responsible for the Corporation's Global Reserves group, which is the internal organization responsible for establishing 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 80% of 2019 year-end reported reserve quantities on a barrel of oil equivalent basis (2018: 80%). 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 letter report, dated February 5, 2020, 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, 2019 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 audited by D&M, in the aggregate, differed by less than 1% (2018: less than 1%) 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, 2019 were $55.73 per barrel for WTI (2018: $65.55; 2017: $51.19) and $62.54 per barrel for Brent (2018: $72.08; 2017: $54.87). New York Mercantile Exchange (NYMEX) natural gas prices used were $2.54 per mcf in 2019 (2018: $3.01; 2017: $3.03).

At December 31, 2019, spot prices for WTI oil closed at $61 per barrel. If crude oil prices during 2020 average below those used in determining 2019 proved reserves, we may recognize negative revisions to our proved reserves at December 31, 2020, which can vary significantly by asset due to differing cost structures. Conversely, if crude oil prices in 2020 remain above those used in determining 2019 proved reserves, we could recognize positive revisions to our proved reserves at December 31, 2020. It is difficult to estimate the magnitude of any potential negative or positive change in proved reserves at December 31, 2020, due to a number of factors that are currently unknown, including 2020 crude oil prices, any revisions based on 2020 reservoir performance, and the levels to which industry costs will change in response to movements in commodity prices.

Following are the Corporation's proved reserves:

	Crude Oil & Condensate (Millions of bbls)					Natural Gas Liquids (Millions of bbls)			
	United States	**Europe**	**Africa**	**Asia & Other**	**Total**	**United States**	**Europe**	**Asia & Other**	**Total**
Net Proved Reserves									
At January 1, 2017	355	210	162	5	732	86	8	—	94
Revisions of previous estimates (a)	13	5	(6)	—	12	56	—	—	56
Extensions, discoveries and other additions	127	2	—	45	174	50	—	—	50
Sales of minerals in place	(21)	(158)	(15)	—	(194)	(6)	(8)	—	(14)
Production	(41)	(10)	(13)	(1)	(65)	(15)	—	—	(15)
At December 31, 2017	433	49	128	49	659	171	—	—	171
Revisions of previous estimates (a)	(3)	(10)	(2)	(2)	(17)	(14)	—	—	(14)
Extensions, discoveries and other additions	114	2	7	2	125	39	—	—	39
Purchase of minerals in place	3	—	—	—	3	1	—	—	1
Sales of minerals in place	(3)	—	—	—	(3)	(8)	—	—	(8)
Production	(43)	(2)	(7)	(1)	(53)	(14)	—	—	(14)
At December 31, 2018	501	39	126	48	714	175	—	—	175
Revisions of previous estimates (a)	**(54)**	**(3)**	**(3)**	**13**	**(47)**	**(29)**	**—**	**—**	**(29)**
Extensions, discoveries and other additions	**112**	**6**	**5**	**34**	**157**	**40**	**—**	**—**	**40**
Production	**(51)**	**(2)**	**(7)**	**(2)**	**(62)**	**(17)**	**—**	**—**	**(17)**
At December 31, 2019	**508**	**40**	**121**	**93**	**762**	**169**	**—**	**—**	**169**
Net Proved Developed Reserves									
At January 1, 2017	245	116	138	5	504	59	3	—	62
At December 31, 2017	239	45	112	5	401	87	—	—	87
At December 31, 2018	266	38	111	4	419	85	—	—	85
At December 31, 2019	**293**	**32**	**107**	**36**	**468**	**90**	**—**	**—**	**90**
Net Proved Undeveloped Reserves									
At January 1, 2017	110	94	24	—	228	27	5	—	32
At December 31, 2017	194	4	16	44	258	84	—	—	84
At December 31, 2018	235	1	15	44	295	90	—	—	90
At December 31, 2019	**215**	**8**	**14**	**57**	**294**	**79**	**—**	**—**	**79**

(a) Revisions resulting from the impact of price changes in production sharing contracts increased proved crude oil and condensate reserves in 2019 by 4 million. (2018: 3 million barrels reduction; 2017: 0 million barrels).

	Natural Gas					Total				
	United States	Europe	Africa	Asia & Other	Total	United States	Europe	Africa	Asia & Other	Total
	(Millions of mcf)					(Millions of boe)				
Net Proved Reserves										
At January 1, 2017	590	220	143	744	1,697	539	255	186	129	1,109
Revisions of previous estimates (a)	171	31	(2)	28	228	97	10	(6)	5	106
Extensions, discoveries and other additions	219	7	—	176	402	214	3	—	74	291
Sales of minerals in place	(18)	(153)	(15)	—	(186)	(29)	(192)	(18)	—	(239)
Production (b)	(82)	(13)	(2)	(103)	(200)	(70)	(12)	(13)	(18)	(113)
At December 31, 2017	880	92	124	845	1,941	751	64	149	190	1,154
Revisions of previous estimates (a)	(24)	(14)	1	(21)	(58)	(21)	(12)	(3)	(5)	(41)
Extensions, discoveries and other additions	177	3	8	104	292	183	3	8	19	213
Purchase of minerals in place	—	—	—	—	—	4	—	—	—	4
Sales of minerals in place	(145)	—	—	—	(145)	(35)	—	—	—	(35)
Production (b)	(75)	(3)	(5)	(132)	(215)	(70)	(3)	(7)	(23)	(103)
At December 31, 2018	813	78	128	796	1,815	812	52	147	181	1,192
Revisions of previous estimates (a)	**(197)**	**(8)**	**(3)**	**24**	**(184)**	**(116)**	**(4)**	**(3)**	**16**	**(107)**
Extensions, discoveries and other additions	**164**	**15**	**—**	**5**	**184**	**179**	**9**	**5**	**35**	**228**
Production (b)	**(80)**	**(4)**	**(5)**	**(133)**	**(222)**	**(81)**	**(3)**	**(8)**	**(24)**	**(116)**
At December 31, 2019	**700**	**81**	**120**	**692**	**1,593**	**794**	**54**	**141**	**208**	**1,197**
Net Proved Developed Reserves										
At January 1, 2017	404	125	132	739	1,400	371	140	160	128	799
At December 31, 2017	526	80	117	696	1,419	414	58	132	121	725
At December 31, 2018	432	77	115	585	1,209	423	51	130	102	706
At December 31, 2019	**400**	**65**	**118**	**500**	**1,083**	**450**	**43**	**127**	**119**	**739**
Net Proved Undeveloped Reserves										
At January 1, 2017	186	95	11	5	297	168	115	26	1	310
At December 31, 2017	354	12	7	149	522	337	6	17	69	429
At December 31, 2018	381	1	13	211	606	389	1	17	79	486
At December 31, 2019	**300**	**16**	**2**	**192**	**510**	**344**	**11**	**14**	**89**	**458**

(a) Revisions resulting from the impact of price changes in production sharing contracts increased proved natural gas reserves in 2019 by 6 million mcf (2018: 22 million mcf decrease; 2017: 22 million mcf decrease).
(b) Natural gas production in 2019 includes 14 million mcf used for fuel (2018: 13 million mcf; 2017: 11 million mcf).

Extensions, discoveries and other additions ('Additions')

2019: Total Additions were 228 million boe, of which 25 million boe (13 million barrels of crude oil, 6 million barrels of NGL and 35 million mcf of natural gas) related to proved developed reserves. Additions to proved developed reserves primarily resulted from new wells drilled in the Bakken shale play in North Dakota. Additions in the U.S. also included two wells drilled in the Gulf of Mexico. Additions to proved undeveloped reserves were 203 million boe (144 million barrels of crude oil, 34 million barrels of NGL and 149 million mcf of natural gas) and are discussed in further detail on page 95.

2018: Total Additions were 213 million boe, of which 6 million boe (3 million barrels of crude oil and 18 million mcf of natural gas) related to proved developed reserves. Additions to proved developed reserves were primarily from drilling activity in the Bakken shale play in North Dakota. Additions to proved undeveloped reserves were 207 million boe (122 million barrels of crude oil, 39 million barrels of NGL and 274 million mcf of natural gas) and are discussed in further detail on page 96.

2017: Total Additions were 291 million boe, of which 11 million boe (4 million barrels of crude oil, 1 million barrels of NGL and 37 million mcf of natural gas) related to proved developed reserves. Additions to proved developed reserves were primarily from drilling activity in the Bakken and North Malay Basin. Additions to proved undeveloped reserves were 280 million boe (170 million barrels of crude oil, 49 million barrels of NGL and 365 million mcf of natural gas) and are discussed in further detail on page 96.

Revisions of previous estimates

2019: Total revisions of previous estimates amounted to a net decrease of 107 million boe, of which revisions of proved developed reserves amounted to a net decrease of 19 million boe (NGL - 7 million barrels decrease and natural gas - 72 million mcf decrease). Revisions to proved developed reserves from the Bakken were a net decrease of 25 million boe with approximately 80% relating to changes in expected recoveries of NGL and natural gas and approximately 20% relating to the impact of lower prices. Net revisions from international assets were an increase of 6 million boe. Revisions associated with proved undeveloped reserves are discussed in further detail on page 96.

2018: Total revisions of previous estimates amounted to a net decrease of 41 million boe, of which revisions of proved developed reserves amounted to a net increase of 3 million boe (crude oil - 4 million barrels increase, NGL - 4 million barrels decrease and natural gas - 20 million mcf increase). Revisions to proved developed reserves primarily relate to the Bakken. Revisions associated with proved undeveloped reserves are discussed in further detail on page 96.

2017: Total revisions of previous estimates amounted to a net increase of 106 million boe, of which revisions of proved developed reserves amounted to a net increase of 126 million boe (41 million barrels of crude oil, 44 million barrels of NGL and 243 million mcf of natural gas). Revisions to proved developed reserves from the Bakken amounted to 85 million boe with approximately 55% resulting from improved reservoir performance, and the remaining 45% resulting from higher prices and an improved cost structure. The Gulf of Mexico and Utica had positive revisions to proved developed reserves totaling 16 million boe due to improved reservoir performance, while higher crude oil prices resulted in revisions to proved developed reserves of 15 million boe in Denmark and Utica. Revisions associated with proved undeveloped reserves are discussed in further detail on page 96.

Sales of minerals in place ('Asset sales')

2018: Asset sales primarily include our former interests in the Utica Basin of Ohio.

2017: Asset sales primarily include our former interests in Norway, Equatorial Guinea, and our enhanced oil recovery assets in the Permian Basin.

Proved Undeveloped Reserves

Following are the Corporation's proved undeveloped reserves:

	United States	Europe	Africa	Asia & Other	Total
			(Millions of boe)		
Net Proved Undeveloped Reserves					
At January 1, 2017	168	115	26	1	310
Revisions of previous estimates	(8)	(3)	(9)	—	(20)
Extensions, discoveries and other additions	209	3	—	68	280
Transfers to proved developed reserves	(32)	—	—	—	(32)
Sales of minerals in place	—	(109)	—	—	(109)
At December 31, 2017	337	6	17	69	429
Revisions of previous estimates	(22)	(7)	(6)	(9)	(44)
Extensions, discoveries and other additions	178	2	8	19	207
Transfers to proved developed reserves	(97)	—	(2)	—	(99)
Sales of minerals in place	(7)	—	—	—	(7)
At December 31, 2018	389	1	17	79	486
Revisions of previous estimates	**(91)**	**—**	**(6)**	**9**	**(88)**
Extensions, discoveries and other additions	**154**	**10**	**5**	**34**	**203**
Transfers to proved developed reserves	**(108)**	**—**	**(2)**	**(33)**	**(143)**
At December 31, 2019	**344**	**11**	**14**	**89**	**458**

Extensions, discoveries and other additions ('Additions')

2019: In the United States, additions from the Bakken shale play in North Dakota were 154 million boe, of which approximately 25% of the change results from additional planned wells to be drilled in the next five years, and approximately 75% results from new wells moved into the five-year plan associated with optimization of drilling locations. Additions in Asia and Other totaling 34 million boe are from the sanction of Phase 2 at Liza Field on the Stabroek Block, offshore Guyana. Other international additions were at the South Arne Field in Denmark and in Libya due to additional planned wells to be drilled.

2018: In the United States, additions from the Bakken shale play in North Dakota were 168 million boe, of which approximately 40% of the change results from additional planned wells to be drilled in the next five years, approximately 35% results from performance associated with improved well completion designs, and approximately 25% results from other changes, primarily the impact of higher crude oil prices. Additions in the Gulf of Mexico were 10 million boe due to additional planned drilling at the Tubular Bells Field. Additions in Asia include 11 million boe at North Malay Basin and 8 million boe at the JDA relating to additional planned wells to be drilled within the next five years.

2017: In the United States, additions from the Bakken were 180 million boe, of which approximately 70% resulted from higher crude oil prices that increased the percentage of proved undeveloped wells in our planned five-year drilling program compared with the prior year. The remaining 30% of Bakken additions reflect the expected improved recovery in future wells from changes in well completion design and reservoir performance. Additions from the Stampede Field in the Gulf of Mexico were 21 million boe, due to completion of further development activities. At the Stabroek Block, offshore Guyana, additions of 45 million boe were recognized for project sanction of the first phase of the Liza Field development. Other international additions were primarily at North Malay Basin due to higher prices.

Revisions of previous estimates

2019: Negative reserve revisions in the United States of 91 million boe were largely from the Bakken (94 million boe), of which approximately 75% resulted from wells moved outside our five-year plan associated with optimization of drilling locations. The remaining 25% of negative revisions in the Bakken were caused by lower commodity prices. The net positive reserve revisions in Asia and Other of 9 million boe relate to the Liza Phase 1 development, offshore Guyana, including the impact of lower crude oil prices on entitlement allocations in the production sharing agreement.

2018: Negative reserve revisions in the United States totaling 22 million boe, primarily resulted from optimizing drilling plans at the Bakken. Negative reserve revisions in international assets primarily resulted from updates in drilling plans in Denmark and North Malay Basin, and the impact of crude oil price changes on our PSC in Guyana.

2017: Total negative reserve revisions of 20 million boe, primarily relate to changes in drilling plans in Libya and lower reserves at certain fields in the Gulf of Mexico and Denmark.

Transfers to proved developed reserves ('Transfers')

2019: Transfers from proved undeveloped reserves included 100 million boe in the Bakken associated with drilling activity, 30 million boe at the Stabroek Block in Guyana where first production was achieved in 2019, and 8 million boe at the Tubular Bells Field in the Gulf of Mexico associated with drilling activity.

2018: Transfers from proved undeveloped reserves included 75 million boe in the Bakken associated with drilling activity, and 22 million boe at the Stampede Field in the Gulf of Mexico where first production was achieved in 2018.

2017: Transfers from proved undeveloped reserves included 24 million boe in the Bakken and 8 million boe at the Penn State Field in the Gulf of Mexico associated with drilling activity.

In 2019, capital expenditures of $1,750 million were incurred to convert proved undeveloped reserves to proved developed reserves (2018: $1,070 million; 2017: $527 million).

At December 31, 2019, projects that have proved reserves that have been classified as undeveloped for a period in excess of five years total 3 million boe, or less than 1% of total proved reserves, primarily related to Libya.

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. Proved reserves from these production sharing contracts for each of the three years ended December 31, 2019 are presented separately below, as well as volumes produced and received during 2019, 2018 and 2017 from these production sharing contracts.

	Crude Oil (Millions of bbls)					Natural Gas (Millions of mcf)				
	United States	Europe	Africa	Asia & Other (a)	Total	United States	Europe	Africa	Asia & Other (a)	Total
Production Sharing Contracts										
Proved Reserves										
At December 31, 2017	—	—	—	49	49	—	—	—	845	845
At December 31, 2018	—	—	—	48	48	—	—	—	796	796
At December 31, 2019	**—**	**—**	**—**	**93**	**93**	**—**	**—**	**—**	**692**	**692**
Production										
2017	—	—	9	1	10	—	—	2	103	105
2018	—	—	—	1	1	—	—	—	132	132
2019	**—**	**—**	**—**	**2**	**2**	**—**	**—**	**—**	**133**	**133**

(a) At December 31, 2019, Asia and Other includes Guyana proved reserves of 87 million barrels of oil (2018: 40 million barrels; 2017: 43 million barrels) and 6 million mcf of natural gas (2018: 11 million mcf; 2017: 11 million mcf).

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 and 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 2019 were $55.73 per barrel for WTI (2018: $65.55; 2017: $51.19) and $62.54 per barrel for Brent (2018: $72.08; 2017: $54.87) and do not include the effects of commodity hedges. NYMEX natural gas prices used were $2.54 per mcf in 2019 (2018: $3.01; 2017: $3.03). 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. In addition, 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	Europe	Africa	Asia & Other
			(In millions)		
2019					
Future revenues	**$ 44,778**	**$ 25,223**	**$ 2,719**	**$ 8,037**	**$ 8,799**
Less:					
Future production costs	**14,176**	**10,189**	**1,178**	**640**	**2,169**
Future development costs	**8,267**	**5,104**	**490**	**301**	**2,372**
Future income tax expenses	**8,560**	**1,291**	**209**	**6,393**	**667**
	31,003	**16,584**	**1,877**	**7,334**	**5,208**
Future net cash flows	**13,775**	**8,639**	**842**	**703**	**3,591**
Less: Discount at 10% annual rate	**5,390**	**3,872**	**376**	**333**	**809**
Standardized Measure of Discounted Future Net Cash Flows	**$ 8,385**	**$ 4,767**	**$ 466**	**$ 370**	**$ 2,782**
2018					
Future revenues	$ 50,948	$ 31,460	$ 3,036	$ 9,183	$ 7,269
Less:					
Future production costs	13,636	9,718	1,311	678	1,929
Future development costs	8,427	6,132	449	301	1,545
Future income tax expenses	10,950	2,641	246	7,496	567
	33,013	18,491	2,006	8,475	4,041
Future net cash flows	17,935	12,969	1,030	708	3,228
Less: Discount at 10% annual rate	7,285	5,437	444	359	1,045
Standardized Measure of Discounted Future Net Cash Flows	$ 10,650	$ 7,532	$ 586	$ 349	$ 2,183
2017					
Future revenues	$ 36,746	$ 20,834	$ 2,958	$ 7,154	$ 5,800
Less:					
Future production costs	13,042	8,802	1,501	782	1,957
Future development costs	6,748	4,601	553	330	1,264
Future income tax expenses	6,379	444	137	5,485	313
	26,169	13,847	2,191	6,597	3,534
Future net cash flows	10,577	6,987	767	557	2,266
Less: Discount at 10% annual rate	4,221	2,904	272	307	738
Standardized Measure of Discounted Future Net Cash Flows	$ 6,356	$ 4,083	$ 495	$ 250	$ 1,528

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

For the Years Ended December 31	2019	2018	2017
		(In millions)	
Standardized Measure of Discounted Future Net Cash Flows at January 1	**$ 10,650**	$ 6,356	$ 4,025
Changes during the year:			
Sales and transfers of oil and gas produced during the year, net of production costs	**(2,842)**	(2,755)	(2,216)
Development costs incurred during the year	**2,262**	1,533	1,679
Net changes in prices and production costs applicable to production	**(5,761)**	7,076	2,330
Net change in estimated future development costs	**(186)**	(1,119)	(568)
Extensions and discoveries (including improved recovery) of oil and gas reserves, less related costs	**1,591**	2,129	1,282
Revisions of previous oil and gas reserve estimates	**(281)**	(630)	644
Net purchases (sales) of minerals in place, before income taxes	**—**	(83)	116
Accretion of discount	**1,635**	929	603
Net change in income taxes	**1,305**	(2,662)	(709)
Revision in rate or timing of future production and other changes	**12**	(124)	(830)
Total	**(2,265)**	4,294	2,331
Standardized Measure of Discounted Future Net Cash Flows at December 31	**$ 8,385**	$ 10,650	$ 6,356

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Following are selected quarterly results of operations (unaudited):

	2019			
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
	(In millions, except per share amounts)			
Sales and other operating revenues	**$ 1,572**	**$ 1,660**	**$ 1,580**	**$ 1,683**
Gross profit (loss) (a)	**$ 361**	**$ 358**	**$ 245**	**$ 252**
Net income (loss)	**75**	**34**	**(166)**	**(183)**
Less: Net income (loss) attributable to noncontrolling interests	**43**	**40**	**46**	**39**
Net income (loss) attributable to Hess Corporation	**32**	**(6)**	**(212)**	**(222)**
Less: Preferred stock dividends	**4**	**—**	**—**	**—**
Net income (loss) attributable to Hess Corporation common stockholders	**$ 28**	**$ (6) (b)**	**(212) (c)**	**(222) (d)**
Net income (loss) attributable to Hess Corporation per common share:				
Basic	**$ 0.09**	**$ (0.02)**	**$ (0.70)**	**$ (0.73)**
Diluted	**$ 0.09**	**$ (0.02)**	**$ (0.70)**	**$ (0.73)**

	2018			
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
	(In millions, except per share amounts)			
Sales and other operating revenues	$ 1,346	$ 1,534	$ 1,793	$ 1,650
Gross profit (loss) (a)	$ 244	$ 310	$ 500	$ 310
Net income (loss)	(65)	(87)	3	34
Less: Net income (loss) attributable to noncontrolling interests	41	43	45	38
Net income (loss) attributable to Hess Corporation	(106)	(130)	(42)	(4)
Less: Preferred stock dividends	11	12	11	12
Net income (loss) attributable to Hess Corporation common stockholders	$ (117) (e)	$ (142) (f)	$ (53) (g)	$ (16) (h)
Net income (loss) attributable to Hess Corporation per common share:				
Basic	$ (0.38)	$ (0.48)	$ (0.18)	$ (0.05)
Diluted	$ (0.38)	$ (0.48)	$ (0.18)	$ (0.05)

(a) Gross profit represents Sales and other operating revenues, less Marketing expenses, Operating costs and expenses, Production and severance taxes, and Depreciation, depletion and amortization.
(b) Includes an after-tax gain of $22 million ($22 million pre-tax) associated with the sale of our remaining acreage in the Utica shale play.
(c) Includes an after-tax charge of $88 million ($88 million pre-tax) relating to a pension settlement and an after-tax charge of $19 million ($21 million pre-tax) related to a cost recovery settlement.
(d) Includes an allocation of noncash income tax expense of $86 million that was previously a component of accumulated other comprehensive income related to our 2019 crude oil hedge contracts, a noncash income tax benefit of $60 million to reverse the valuation allowance on net deferred tax assets in Guyana upon achieving first production from the Liza Phase 1 development, and a charge after income taxes and noncontrolling interests of $16 million ($30 million pre-tax) for transaction related costs for Hess Midstream Partners LP's acquisition of HIP and associated corporate restructuring.
(e) Includes a net after-tax severance charge of $37 million ($37 million pre-tax), an after-tax charge of $27 million ($27 million pre-tax) related to the premium paid for the retirement of debt, and a noncash income tax benefit of $30 million to offset a noncash income tax expense recognized in other comprehensive income, resulting from a reduction in our pension liabilities.
(f) Includes an after-tax gain of $10 million ($10 million pre-tax) associated with the sale of our interests in Ghana, an after-tax charge of $26 million ($26 million pre-tax) related to the premium paid for the retirement of debt, and an after-tax charge of $58 million ($58 million pre-tax) resulting from the settlement of legal claims related to former downstream interests.
(g) Includes an after-tax gain of $14 million ($14 million pre-tax) associated with the sale of our interests in the Utica shale play in eastern Ohio, noncash after-tax charges of $73 million ($73 million pre-tax) in connection with vacated office space, and an allocation of noncash income tax expense of $12 million to offset the recognition of a noncash income tax benefit recorded in other comprehensive income resulting from changes in fair value of our 2019 crude oil hedge contracts.
(h) Includes a noncash income tax benefit of $73 million to offset the recognition of a noncash income tax expense recorded in other comprehensive income primarily resulting from changes in fair value of our 2019 crude oil hedge contracts.

The results of operations for the periods reported herein should not be considered as indicative of future operating results.

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, 2019, 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, 2019.

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, 2019 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

On February 19, 2020, the Corporation filed with the Secretary of State of Delaware a certificate of elimination (Certificate of Elimination) of its 8.00% Series A Mandatory Convertible Preferred Stock, par value $1.00 per share (the Mandatory Convertible Preferred Stock), which has the effect of eliminating from the Corporation's Restated Certificate of Incorporation, as amended, all matters set forth in the Certificate of Designations of Mandatory Convertible Preferred Stock filed with the Secretary of State of Delaware on February 10, 2016. All outstanding shares of Mandatory Convertible Preferred Stock issued by the Corporation were previously converted into common stock of the Corporation as of January 31, 2019.

The foregoing summary of the Certificate of Elimination is qualified in its entirety by reference to the full text of the Certificate of Elimination, a copy of which is filed herewith as Exhibit 3(4).

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 2020 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 2020 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 2020 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 2020 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 2020 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.

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.
3(5)	By-laws of Registrant incorporated by reference to Exhibit 3(2) of Form 8-K of Registrant filed on November 9, 2015.
4(1)	Credit Agreement, dated as of April 18, 2019, 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 April 23, 2019.
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.
	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 8, 2019.
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)*	Hess Corporation Pension Restoration Plan, dated January 19, 1990, incorporated by reference to Exhibit 10(9) of Form 10-K of Registrant for the fiscal year ended December 31, 1989. (P)
10(5)*	Amendment, dated December 31, 2006, to Hess Corporation Pension Restoration Plan, incorporated by reference to Exhibit 10(10) of Form 10-K of Registrant for the fiscal year ended December 31, 2006.
10(6)*	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(7)*	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(8)*	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(9)*	Form of Restricted Stock Award Agreement under Registrant's Amended and Restated 2008 Long-term Incentive Plan, incorporated by reference to Exhibit 10(2) of Form 10-Q of Registrant for the three months ended March 31, 2015.
10(10)*	Compensation program description for non-employee directors, incorporated by reference to Item 1.01 of Form 8-K of Registrant filed on January 4, 2007.
10(11)*	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(12)*	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 Michael Turner and John B. Hess).

10(13)*	Form of Change in Control Termination Benefits Agreement, dated as of August 3, 2015, between the Registrant and Michael R. Turner, incorporated by reference to Exhibit 10(3) of Form 10-Q of Registrant for the three months ended June 30, 2015. Substantially identical agreements (differing only in the signatories thereto) were entered into between the Registrant and four other senior officers.
10(14)*	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(15)*	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(16)*	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(17)*	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(18)*	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, 2019. Substantially identical agreements were entered into by the Registrant during 2018.
10(19)*	Form of Stock Option 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, 2019. Substantially identical agreements were entered into by the Registrant during 2018.
10(20)*	Form of Performance Award Agreement under the 2017 Long-Term Incentive Plan, incorporated by reference to Exhibit 10(3) of Form 10-Q of Registrant for the three months ended March 31, 2019. Substantially identical agreements were entered into by the Registrant during 2018.
10(21)*	Separation Agreement, dated November 6, 2019, between Registrant and Michael R. Turner.
21	Subsidiaries of Registrant.
24	Power of Attorney (included on the signatures page of this Annual Report on Form 10-K).
23(1)	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm, dated February 20, 2020.
23(2)	Consent of DeGolyer and MacNaughton dated February 20, 2020.
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).
99(1)	Letter report of DeGolyer and MacNaughton, Independent Petroleum Engineering Consulting Firm, dated February 5, 2020, on proved reserves audit as of December 31, 2019 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, 2019 has been formatted in Inline XBRL.

** These exhibits relate to executive compensation plans and arrangements.*

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 20th day of February 2020.

HESS CORPORATION
(Registrant)

By /s/ JOHN P. RIELLY
(John P. Rielly)
Senior 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 20, 2020
/s/ JAMES H. QUIGLEY **James H. Quigley**	Director and Chairman of the Board	February 20, 2020
/s/ RODNEY F. CHASE **Rodney F. Chase**	Director	February 20, 2020
/s/ TERRENCE J. CHECKI **Terrence J. Checki**	Director	February 20, 2020
/s/ LEONARD S. COLEMAN JR. **Leonard S. Coleman Jr.**	Director	February 20, 2020
/s/ JOAQUÍN DUATO **Joaquín Duato**	Director	February 20, 2020
/s/ EDITH E. HOLIDAY **Edith E. Holiday**	Director	February 20, 2020
/s/ DR. RISA LAVIZZO-MOUREY **Dr. Risa Lavizzo-Mourey**	Director	February 20, 2020
/s/ MARC S. LIPSCHULTZ **Marc S. Lipschultz**	Director	February 20, 2020
/s/ DAVID MCMANUS **David McManus**	Director	February 20, 2020
/s/ DR. KEVIN O. MEYERS **Dr. Kevin O. Meyers**	Director	February 20, 2020
/s/ JOHN P. RIELLY **John P. Rielly**	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 20, 2020
/s/ WILLIAM G. SCHRADER **William G. Schrader**	Director	February 20, 2020

Exhibit 3(4)

CERTIFICATE OF ELIMINATION OF THE 8.00% SERIES A MANDATORY CONVERTIBLE PREFERRED STOCK OF HESS CORPORATION

Pursuant to Section 151(g)
of the General Corporation Law
of the State of Delaware

Hess Corporation, a corporation organized and existing under the laws of the State of Delaware (the "Company"), in accordance with the provisions of Section 151(g) of the General Corporation Law of the State of Delaware, hereby certifies as follows:

1. That, pursuant to Section 151 of the General Corporation Law of the State of Delaware and authority granted in the Restated Certificate of Incorporation of the Company, as theretofore amended, the Board of Directors of the Company, by resolution duly adopted, authorized the issuance of a series of 575,000 shares of 8.00% Series A Mandatory Convertible Preferred Stock, par value $1.00 per share (the "Mandatory Convertible Preferred Stock"), and established the voting powers, designations, preferences and relative, participating and other rights, and the qualifications, limitations or restrictions thereof, and, on February 10, 2016, filed a Certificate of Designations with respect to such Mandatory Convertible Preferred Stock in the office of the Secretary of State of the State of Delaware.

2. That no shares of said Mandatory Convertible Preferred Stock are outstanding and no shares thereof will be issued subject to said Certificate of Designations.

3. That the Board of Directors of the Company has adopted the following resolutions:

> WHEREAS, by resolution of the Board of Directors of Hess Corporation, a Delaware corporation (the "Company"), and by a Certificate of Designations (the "Certificate of Designations") filed in the office of the Secretary of State of the State of Delaware on February 10, 2016, the Company authorized the issuance of a series of 575,000 shares of 8.00% Series A Mandatory Convertible Preferred Stock, par value $1.00 per share, of the Company (the "Mandatory Convertible Preferred Stock") and established the voting powers, designations, preferences and relative, participating and other rights, and the qualifications, limitations or restrictions thereof; and
>
> WHEREAS, all 575,000 shares of such Mandatory Convertible Preferred Stock were issued by the Company and all such shares have been converted into Common Stock of the Company as of January 31, 2019; and

WHEREAS, as of the date hereof, no shares of such Mandatory Convertible Preferred Stock are outstanding and no shares of such Mandatory Convertible Preferred Stock will be issued subject to said Certificate of Designations; and

WHEREAS, it is desirable that all matters set forth in the Certificate of Designations with respect to such Mandatory Convertible Preferred Stock be eliminated from the Restated Certificate of Incorporation, as heretofore amended, of the Company.

NOW, THEREFORE, BE IT AND IT HEREBY IS

RESOLVED, that all matters set forth in the Certificate of Designations with respect to such Mandatory Convertible Preferred Stock be eliminated from the Restated Certificate of Incorporation, as heretofore amended, of the Company; and it is further

RESOLVED, that the officers of the Company be, and hereby are, authorized and directed to file a Certificate with the office of the Secretary of State of the State of Delaware setting forth a copy of these resolutions whereupon all matters set forth in the Certificate of Designations with respect to such Mandatory Convertible Preferred Stock shall be eliminated from the Restated Certificate of Incorporation, as heretofore amended, of the Company.

4. That, accordingly, all matters set forth in the Certificate of Designations with respect to the Mandatory Convertible Preferred Stock be, and hereby are, eliminated from the Restated Certificate of Incorporation, as heretofore amended, of the Company.

IN WITNESS WHEREOF, Hess Corporation has caused this Certificate to be executed by its duly authorized officer this 19th day of February, 2020.

HESS CORPORATION

By: /s/ Timothy B. Goodell
Name: Timothy B. Goodell
Title: Senior Vice President, General Counsel and Corporate Secretary

Exhibit 4(12)

DESCRIPTION OF HESS CORPORATION'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

As of the date of the Annual Report on Form 10-K of which this exhibit is a part of, Hess Corporation has one class of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended: our common stock.

The following description of our registered securities is a brief summary. This summary is subject to the General Corporation Law of the State of Delaware (the "**DGCL**") and certain provisions of our restated certificate of incorporation, as amended, and our by-laws, as amended, each of which is filed as an exhibit to the Annual Report on Form 10-K. This summary does not include all of the provisions of our restated certificate of incorporation or by-laws. These statements do not purport to be complete, or to give full effect to the provisions of statutory or common laws, and are subject to, and are qualified in their entirety by reference to, the terms and detailed provisions of the restated certificate of incorporation, of the by-laws and of the applicable provisions of the DGCL. We urge you to read our full restated certificate of incorporation and by-laws.

DESCRIPTION OF COMMON STOCK

General

Under our restated certificate of incorporation, we are authorized to issue up to 600,000,000 shares of common stock, par value $1.00 per share. Our shares of common stock are registered pursuant to Section 12 of the Securities Exchange Act of 1934, as amended, and are listed on the New York Stock Exchange under the trading symbol "HES". Our shares are issued in registered form. Every holder of our shares is entitled to a share certificate. Holders of our shares are entitled, subject to the prior rights, if any, of holders of shares of any series of preferred stock that the board of directors may establish, to such dividends as may be declared by our board of directors if there are sufficient funds to legally pay a dividend.

Voting Rights

The holders of our shares of common stock are entitled to one vote for each share held of record and may vote by proxy. Except as may be otherwise provided by applicable law, our restated certificate of incorporation or our by-laws, all matters other than the election of directors shall be decided by a majority of the shares present in person or represented by proxy and entitled to vote thereon at a duly held meeting of stockholders at which a quorum is present.

Liquidation, Dissolution or Winding-Up

In the event of our liquidation, dissolution or winding-up, the holders of our shares of common stock are entitled to share ratably according to the number of shares held by them in all remaining assets available for distribution to the holders of our shares after discharge of outstanding liabilities and payment of such liquidation preference, if any, of any series of preferred stock that our board of directors may establish.

Take-over Provisions

Certain provisions of our restated certificate of incorporation and by-laws may have the effect of delaying, deferring or preventing a change of control in connection with certain extraordinary corporate transactions.

Our restated certificate of incorporation and by-laws provides that our directors are elected annually at each annual meeting of stockholders and serve one-year terms. In addition, the restated certificate of incorporation and the by-laws require (i) approval of holders of 80% of our voting stock to remove directors or to amend, alter or repeal the provisions as to director election and removal and other related provisions, (ii) advance notice of, and a specified procedure for, shareholder nominations for director, (iii) the taking of stockholder action only at annual or special meetings (to be called only by the chairman of the board or the president and shall be called by the secretary at the request of the board of directors pursuant to a resolution approved by a majority of the entire board) and prohibiting stockholder action by written consent, and (iv) the filling of vacancies on the board by remaining directors, though less than a quorum. Such provisions of the restated certificate of incorporation and the by-laws may make it more difficult for a person or entity to acquire and exercise control of the company and remove incumbent directors and officers.

We are also subject to the anti-takeover provisions of Section 203 of the DGCL.

Annual Stockholder Meetings

Annual meetings of our stockholders are held on the date designated in accordance with our by-laws. Written notice must be delivered in person or mailed to each stockholder entitled to vote not less than ten nor more than 50 days before the date of the meeting. The presence in person or by proxy of the holders of record of a majority of our issued and outstanding shares entitled to vote at such meeting constitutes a quorum for the transaction of business at meetings of the stockholders, except as otherwise provided by the DGCL, by the restated certificate of incorporation, or by the by-laws. Special meetings of our stockholders may be called for any purpose by the chairman of the board or the president and shall be called by the secretary at the request of the board of directors pursuant to a resolution approved by a majority of the entire board. Written notice must be delivered in person or mailed to each stockholder entitled to vote at least ten days before the date of such meeting.

Other Rights

Holders of our shares of common stock have no preemption, redemption, conversion or other subscription rights.

Transfer Agent

The transfer agent and registrar for our common stock is Computershare Trust Company, N.A.

Exhibit 10(21)

HESS COPORATION
1501 McKinney Street
Houston, TX 77010

November 6, 2019

Via Hand Delivery
Mike Turner

Dear Mike:

Thank you for your outstanding tenure and service to Hess Corporation (hereinafter “Hess” or “Company”). This letter confirms our agreement that you will separate from employment with Hess on April 3, 2020 (hereinafter “Separation Date”).

From January 1, 2020 until your Separation Date, you will relinquish the title of Senior Vice President Production and agree to assist with transitioning this role and its responsibilities to Gerbert Schoonman.

In exchange for continuing your employment until your Separation Date, assisting with transitioning your role, and signing and complying with the terms and conditions set forth in the attached General Release, the Company offers the payments described (in Section II) below.

I. Regardless of whether you sign the enclosed General Release:

EMPLOYMENT STATUS. You and the Company intend for you to remain an employee of the Company until your Separation Date and to assist with transitioning your role to Gerbert Schoonman. All Company compensation and benefits will cease as of your Separation Date, except as expressly set forth below or as otherwise required by law.

FINAL PAY. You will receive a check no later than the payday following your Separation Date with your earnings through the Separation Date plus pay for any accrued but unused vacation (all Payments are subject to applicable deductions and withholdings).

II. If you continue your employment until the Separation Date and sign the enclosed General Release (and do not revoke it within the time period set forth therein), you will also receive the following:

SPECIAL PAYMENTS. In exchange for signing the General Release and complying with the terms and conditions set forth therein, you will receive a **first payment of $1,000,000** (subject to applicable deductions and withholdings) on **October 9, 2020**.

Assuming continued compliance with the terms and conditions of the General Release, you will receive a **second payment of $1,000,000** (subject to applicable deductions and withholdings) on **April 9, 2021**.

To qualify for the Special Payments, you must sign and date the enclosed General Release after your Separation Date and return the signed General Release to Brent Schwartz in the Human Resources Department no later than **April 25, 2020**.

YOU SHOULD CONSULT WITH AN ATTORNEY BEFORE YOU SIGN THE GENERAL RELEASE.

After you sign the General Release, you will have seven (7) days to change your mind and revoke the General Release (as described in the General Release). If you do not revoke the General Release in writing by the end of the seven (7) day period, the General Release will become effective at the end of such seven (7) days.

III. In addition to the items set forth above, the following is generally applicable to any employee separating from employment with the Company:

BENEFIT COVERAGE. You are eligible for the Hess Retiree Medical Plan, which is the same as the Hess Medical Plan for active employees except vision coverage is not included. To enroll in the Retiree Medical Plan, when you leave Hess call the Hess Benefits Center at Empyrean at 1-877-511-4377, Option 1. Under the Retiree Medical Plan, you can also cover your spouse or domestic partner under age 65 and your dependent children under age 26. You will be billed directly each month for the cost of Retiree Medical coverage.

If you do not enroll in the Retiree Medical Plan, medical and dental coverage for which you are presently enrolled under the Company's medical and/or dental benefits plans will cease thirty (30) days following your Separation Date.

Basic Life Insurance and Optional Life Insurance coverage cease on your Separation Date, but may be converted to individual policies, provided you apply within thirty-one (31) days from the date your coverage ends.

Long Term Disability coverage ceases on your Separation Date, and Travel Accident coverage ceases on your Separation Date and neither can be converted to individual policies. Family Accident coverage ends on your Separation Date but may be converted to an individual policy, provided you apply within thirty-one (31) days from your Separation Date.

401(k) SAVINGS PLAN. Your ability to contribute to the 401k Savings Plan (and any matching contributions by the Company) will cease on your Separation Date. Contact the Benefits Center directly at 877-511-4377 to discuss options. Please contact your accountant or investment advisor concerning the tax consequences of withdrawal and rollover of 401(k) account balances.

PENSION ELIGIBILITY. You participated in the Company's final average pay plan formula. Under the terms of this plan, if you had five or more years of service, or one year of service and have reached age 65 by your Separation Date, you will be entitled to a pension at age 65. If you have ten (10) or more years of service by your Separation Date, you may request payment of this pension any time after age 55.

STOCK OPTIONS AND EQUITY/EQUITY-BASED INTERESTS. You should carefully review the Company's Benefit Plan Documents and information available on the Fidelity site to determine your specific circumstances regarding long term incentive awards. All terms and conditions are solely governed by these Plan Documents.

REFERENCES. In response to any requests for job references, the Company will confirm your job title and dates of employment and, if authorized in writing by you, your most recent salary.

EXIT PROCEDURE. You must settle all outstanding financial obligations to the Company including travel advances and expense reports. Any Company property, including Company phones, computers and computer equipment, credit cards, and employee identification, must be surrendered. You must also return to the Company all documents and other materials that are the property of the Company, its subsidiary and affiliated companies, predecessors, successors and assigns and its and their respective, officers, directors, owners, members, shareholders, partners, agents and employees.

AFFIRMATION OF DOCUMENTS.
In connection with your employment, you may have signed one or more agreements and/or received one or more policies concerning your obligations regarding:

1. the nondisclosure of trade secrets and other confidential and proprietary information of the Company;

2. disclosure of and assignment to the Company of developments, discoveries, inventions, know-how and improvements; and

3. non-competition, non-solicitation, and non-recruitment of the Company's employees following the Separation Date;

As part of our normal termination procedures, we are taking this opportunity to advise you that the obligations specified in these agreements and/or policies continue to remain in effect notwithstanding the end of your employment.

We realize that you will want to review this letter carefully. Please contact the Human Resources Department if you have any questions about the information provided here. If you agree with the terms and conditions set forth in this letter, please sign where indicated below.

Yours truly,

/s/ A.P. (Andy) Slentz
A.P. (Andy) Slentz
SVP Global Human Resources

Enclosure

ACKNOLWEDGED AND AGREED:

/s/ Mike Turner 11/6/19
Mike Turner **Date**

HESS CORPORATION

GENERAL RELEASE

In connection with My separation from employment effective **April 3, 2020** ("Separation Date"), this General Release is given by the Releaser, **Mike Turner**, referred to as "I," "Me" or "My," to HESS CORPORATION, its subsidiaries and affiliated companies, predecessors, successors and assigns and its and their respective, officers, directors, owners, members, shareholders, partners, agents and employees, individually and in their official capacities, collectively referred to as "You", "Your", or "Released Parties."

1. General Release. In consideration of Your issuance of the Special Payments, described in Paragraph 2 below, I hereby waive, release and give up all rights or claims which I may have against You, including but not limited to all causes of action, claims, damages, judgments or agreements of any kind arising from or in connection with My employment with You and/or the separation therefrom. This General Release releases all rights or claims, including those of which I am not aware and those not mentioned in this General Release. This General Release applies to rights or claims resulting from anything that has happened up to the date that I sign this General Release, but not any that may arise after I sign it.

A. I specifically release the following rights or claims, as well as any other rights or claims I might have against You: All rights or claims in connection with My employment and separation from employment with You, including

(i) Title VII of the Civil Rights Act, as amended; the Age Discrimination in Employment Act, as amended; the Americans with Disabilities Act of 1990, as amended; the Older Workers Benefit Protection Act; the Equal Pay Act; the Family and Medical Leave Act of 1993; the Fair Credit Reporting Act; the Sarbanes-Oxley Act of 2002; the National Labor Relations Act; the Immigration Reform and Control Act; the Occupational Safety and Health Act; the Uniformed Services Employment and Reemployment Rights Act of 1994; the False Claims Act; the Employee Retirement Income Security Act of 1974; the federal Worker Adjustment and Retraining Act; Sections 503 and 504 of the Rehabilitation Act of 1973, United States Executive Orders 11246 and 11375, Regulations of Federal Contract Compliance Programs, and

(ii) Texas Human Rights Act; Texas Blacklisting Law; Texas Payment of Wages Law; Texas Minimum Wage Law; Texas Labor Code; Texas AIDS Testing Law; Texas Genetic Testing Law; Texas Fair Credit Reporting Act; Texas Court Attendance and Witness Duty Leave Law; Texas Military Leave and Re-Employment Rights Law; and

(iii) all laws or claims pertaining to breach of employment contract or wrongful termination, retaliation (including, but not limited to, the retaliation provisions of any worker's compensation law), harassment, defamation, libel or slander, detrimental reliance, emotional distress, attorney fees, costs, disbursements, expenses, or any whistle blower or other laws relating in any way whatsoever to My employment with You and the termination of My employment, all waivable claims under or based on any state constitution; and all claims in connection with the Second Amended and Restated 1995 Long-Term Incentive Plan (except with respect to any vested, unexercised stock options issued under such plan).

B. By signing this General Release, I understand that I am providing a complete waiver of all claims to the maximum extent permitted by law, whether known or unknown, that may have arisen up to the date that I sign this General Release (except as otherwise expressly set forth herein).

C. I understand, acknowledge and agree that I have no further right, title or interest with respect to any and all unvested stock options and any and all other unvested equity interests relating to the Released Parties (including subsidiary or affiliated companies), and that any and all such unvested stock options and any and all other unvested equity or equity-based interests are automatically forfeited and terminated as of My Separation Date.

D. I understand, acknowledge and agree that the final payroll check I have received is made in complete satisfaction of any and all claims for accrued wages, salary, commissions, overtime premiums, vacation pay, holiday pay and any other pay for time worked, and leave of any kind to which I am, was, or may be entitled. I expressly represent and acknowledge that the Company owes me no wages or other compensation, Payment, severance, or money of any kind or nature, and that as of the Separation Date, I have been fully compensated for all hours worked and services provided during my employment with You.

E. This does not release You from any obligation for any vested, accrued benefits due Me as of the Separation Date under any of Your employee benefit plans, such as, but not limited to, the Medical Benefit Plan, Long Term Disability Insurance Plan, Sickness and Injury Pay Plan, 401(k) Savings Plan and Pension Plan, or from any claims under the Workers' Compensation or Unemployment Compensation laws.

2. Special Payments. As consideration for entering into this General Release and complying with the terms and conditions set forth herein, I will receive a **first payment of $1,000,000** (subject to applicable deductions and withholdings) on **October 9, 2020**.

And assuming continued compliance with the terms and conditions of the General Release, I will receive a **second payment of $1,000,000** (subject to applicable deductions and withholdings) on **April 9, 2021**.

These Special Payments exceed anything I would otherwise be entitled to if I did not sign this General Release. I understand that these Special Payments will not be counted for any purpose under the terms of Your employee benefit plans.

3. Future Matters. If I file a charge or complaint with the United States Equal Employment Opportunity Commission or any other federal, state or local government agency, or anyone files a charge or complaint on My behalf, I understand that, to the maximum extent permitted by law, this General Release will bar My right to receive any monetary award or other personal recovery with regard to any such charge or complaint. In addition, I expressly (i) agree not to be a class representative or be part of a class regarding any action under ERISA, or otherwise to bring an action under ERISA on behalf of a plan or trust for relief for such plan or trust under ERISA, and (ii) to the extent permitted by law, agree not to retain the benefits of any decision, judgment or settlement in any such action, for any rights or claims arising from or resulting from anything that has happened up to the date that I sign this General Release.

Nothing in this General Release prohibits Me from reporting possible violations of United States federal law or regulation to any governmental agency or entity, including but not limited to, the United States Department of Justice, the United States Securities and Exchange Commission, the United States Congress, and any Inspector General of any United States federal agency, or making other disclosures that are protected under the whistleblower provisions of United States federal, state or local law or regulation; provided that I will use My reasonably best efforts to (1) disclose only information that is reasonably related to such possible violations or that is requested by such agency or entity, and (2) request that such agency or entity treat such information as confidential. I do not need the prior authorization from You to make any such reports or disclosures and I am not required to notify You that I have made such reports or disclosures. This General Release does not limit My right to receive an award for information provided to any governmental agency or entity.

4. Confidential Matters/Return of Property. I will not disclose the nature, amount or fact that I have been offered, accept or receive the Payments or benefits described in Paragraph 2 above to anyone other than My attorney, My accountant or other tax counsel, or My spouse (if applicable), and then only if he or she agrees to keep this information confidential, or as otherwise required by law.

I acknowledge that, during My employment with You, I have acquired proprietary and other confidential information of Yours (herein “Proprietary Information”), including, without limitation, information relating to Your operations, personnel, budgets, business plans and prospects, assets, financial and technical data, financial statements and knowledge concerning Your organization and the skills and talents of Your employees, but excluding information which becomes generally known to the public (other than through me, directly or indirectly). In addition to any other obligations that I may have to You, I will not use, for the benefit of myself or any other person or entity, or disclose to any person or entity (except as described above in connection with obtaining advice with respect to this General Release or except to the extent I am so compelled by subpoena or an order issued by a court of competent jurisdiction or government agency or except as otherwise required by law) any Proprietary Information, or other matters of which I am aware and which matters were considered by You to be confidential. Within 30 days after I sign this Agreement, I will return to You all documents, materials and property in My possession, custody or control that are Your property.

5. Cooperation. I agree that I will cooperate with You and Your legal counsel in connection with any current or future investigation or litigation relating to any matter with which I was involved or of which I have knowledge or which occurred during My employment with You. Such assistance will include, but not be limited to, depositions and testimony and will continue until such matters are resolved. You will provide Me with reasonable notice whenever possible of the need of My cooperation.

6. Continuing Obligations. I agree that any provisions of Your policies and/or any agreements relating to nondisclosure of trade secrets and other confidential and proprietary information, restrictive covenants, intellectual property or conflicts of interest which contain My obligations that extend beyond My employment with You will continue to remain in full force and effect.

7. Non-Competition. I agree that during the period commencing on the Separation Date and ending April 1, 2022 (one year following my second Special Payment) (the “Restricted

Period"), I will not, directly or indirectly, in any manner or capacity be employed by, serve as a director or manager of, act as a consultant to or maintain any ownership interest in, any business that competes with You, including, without limitation, any business which is engaged in the business of exploring for, developing or producing, crude oil or natural gas (provided that My ownership of securities of less than one percent (1%) of any class of securities of a public company shall not, by itself, be considered to be a material ownership interest). I further agree that during the Restricted Period, I will not interfere with the relationship between You and any person (including, without limitation, any business or governmental entity) that is, or during the six months immediately preceding My Separation Date, was Your client, customer, supplier, licensee, or partner, or had any other business relationship with You.

8. Non-Disparagement. I agree that I will not disparage or encourage or induce others to disparage You or any of the Released Parties. For the purposes of this agreement, the term "disparage" includes, without limitation, comments or statements on the internet, to the press and/or media, to any Released Party or to any individual or entity with whom any of the Released Parties have a business relationship which would adversely affect in any manner (i) the conduct of the business of any of the Released Parties (including, without limitation, any business plans or prospects) or (ii) the business reputation of the Released Parties.

9. Non-Solicitation of Employees. I agree that for the Restricted Period, I will not, without the prior written consent by Your Senior Vice President of Human Resources, hire or seek to hire (whether on My own behalf or on behalf of some other person or entity) any person who is at the time Your employee, executive, consultant, independent contractor, representative, or other agent of Yours or any of Your affiliates, nor will I induce or encourage any employee, executive, consultant, independent contractor, representative, or other agent of Yours, to terminate his or her employment or business relationship with You. I represent that I have not engaged in any activities since My Separation Date that would violate this Section.

10. Violation of Agreements. If I violate any of the provisions of this General Release, in addition to any other available remedies, You can terminate any remaining Payments to Me and recover any portion of the Special Payments that You already paid Me (except that I understand that I will be able to retain a minimum of $2,500 of the Special Payments set forth in Paragraph 2 above as consideration for this General Release and I acknowledge and agree that this General Release will otherwise remain in full force and effect).

any portion of this General Release is found to be unenforceable but such portion would be enforceable if some part thereof were deleted or modified, then such portion will apply with such deletion or modification as is necessary to make it enforceable to the fullest extent permitted by law. If any such portion (other than the general provisions contained in Paragraph 1 above) cannot be modified to be enforceable, such portion will be deemed severed from this General Release and will not affect the validity or enforceability of the remainder of this General Release. With the exception of the waiver and release of ADEA claims, if for any reason the general provisions contained in Paragraph 1 above are found to be unenforceable by a court of competent jurisdiction and cannot be modified to be enforceable, You may rescind the General Release, terminate any remaining Payment to Me and recover any portion of the Special Payment that You have already paid Me (and/or seek restitution and/or offset of such Payment to the extent permitted by law). If the waiver and release of ADEA claims is found to be unenforceable and I prevail on an ADEA claim, the court shall determine the extent to which You are entitled to restitution, recoupment or setoff with respect to Payment made to Me under this Agreement and/or recovery of any attorneys' fees or costs authorized under federal law.

12. Who is Bound. I am bound by this General Release. Anyone who succeeds to My rights and responsibilities, such as My heirs or the executor of My estate, is also bound. This Release is made for Your benefit and all who succeed to Your rights and responsibilities, such as Your successors or assigns.

13. No Admission of Wrongdoing. The making of this Agreement is not intended, and shall not be construed, as an admission that the Company or any of the released parties have violated any federal, state or local law (statutory or decisional), ordinance or regulation, breached any contract or committed any wrongdoing whatsoever against You or otherwise.

14. Governing Law, Interpretation and Enforcement. This Agreement shall, for all purposes, be construed, governed and enforced in accordance with the laws of the State of Texas without regard to Texas' principles of conflicts of law. If any provision of this Agreement should need to be interpreted or construed, I and You agree that the entity interpreting or constructing this Agreement shall not apply a presumption against one party by reason of the rule of construction that a document is to be construed more strictly against the party who prepared the document. Additionally, any action to enforce the terms of this Agreement shall be commenced in Houston, Texas. Both parties consent to personal jurisdiction in federal and state courts in Houston, Texas.

15. Review and Signature. I further state:

A. I have carefully read this General Release, which I acknowledge is written in terms that I fully understand.

B. I have had an opportunity to consider this General Release for at least 21 days and I understand and agree that any modifications to this General Release, whether material or immaterial, will not restart this 21 day period.

C. You advised Me in writing to talk to an attorney before signing this General Release, and I have had an opportunity to do so if I so chose.

D. I fully understand that once I have signed this General Release I may change My mind and choose to revoke My execution within seven (7) days from when I sign it and that any revocation of this General Release must be in writing and, within such seven (7) day period, either hand-delivered or mailed to Brent Schwartz, Human Resources (if mailed, the revocation must be postmarked within seven (7) days of the date upon which this General Release was signed by Me).

E. I UNDERSTAND THAT TO RECEIVE THE SPECIAL PAYMENT DESCRIBED IN PARAGRAPH 2 ABOVE, I MUST SIGN AND DATE THIS GENERAL RELEASE AND RETURN THE SIGNED GENERAL RELEASE NO EARLIER THAN THE SEPARATION DATE AND NO LATER THAN April 25, 2020. This General Release must be returned to Brent Schwartz, Human Resources. I understand that You will not make any Payment or provide any benefits pursuant to this General Release until after the seven (7) day revocation period expired without My having revoked this General Release. To the extent I have signed this Agreement prior to expiration of the 21-day period to consider it, I hereby waive my right to the balance of such period of consideration and acknowledge that my waiver of the remainder of such period is voluntary, and not due to any threats or coercion by You.

F. The only promises or representations made to Me to sign this General Release are those stated in this General Release, and I have not relied on any other promises or representations in signing this General Release.

G. I am signing this General Release voluntarily.

H. I understand and agree to the terms of this General Release.

I. This General Release contains the entire understanding of You and I regarding the subject matter hereof. This General Release may be modified only in a writing signed by You and Me and referring specifically hereto.

AGREED TO AND ACCEPTED, AND
EXECUTED this ______ day of __________, 2020

____
Mike Turner

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 L.L.C.	100	Delaware
Hess Bakken Investments III L.L.C.	100	Delaware
Hess Bakken Investments IV L.L.C.	100	Delaware
Hess Bakken Processing L.L.C.	47	Delaware
Hess Baldpate-Penn State L.L.C.	100	Delaware
Hess Canada (Aspy) Exploration Limited	100	Cayman Islands
Hess Canada Exploration Limited	100	Cayman Islands
Hess Canada Oil and Gas ULC	100	Canada
Hess Capital Limited	100	Cayman Islands
Hess Capital Services Corporation	100	Delaware
Hess Capital Services L.L.C.	100	Delaware
Hess Conger LLC	100	Delaware
Hess Denmark Aps	100	Denmark
Hess Equatorial Guinea Investments Limited	100	Cayman Islands
Hess Exploration and Production Malaysia B.V.	100	The Netherlands
Hess Energy Exploration Limited	100	Delaware
Hess Exploration & Production Holdings Limited	100	Delaware
Hess Exploration Services Inc.	100	Delaware
Hess Finance	100	England & Wales
Hess GOM Deepwater L.L.C.	100	Delaware
Hess GOM Exploration L.L.C.	100	Delaware
Hess Holdings GOM Ventures L.L.C.	100	Delaware
Hess Guyana Exploration (Liza) Limited	100	Cayman Islands
Hess Guyana Exploration Limited	100	Cayman Islands
Hess Holdings EG Limited	100	Cayman Islands
Hess Holdings West Africa Limited	100	Cayman Islands
Hess Hungary Finance KFT	100	Hungary
Hess (Indonesia-VIII) Holdings Limited	100	Cayman Islands
Hess Infrastructure Partners LP	47	Delaware
Hess International Holdings Corporation	100	Delaware
Hess International Holdings Limited	100	Cayman Islands
Hess International Receivables Limited	100	Cayman Islands
Hess International Sales Limited	100	Cayman Islands
Hess Libya Exploration Limited	100	Cayman Islands
Hess Libya (Waha) Limited	100	Cayman Islands
Hess Limited	100	England & Wales
Hess Llano L.L.C	100	Delaware
Hess Middle East New Ventures Limited	100	Cayman Islands
Hess Midstream Operations LP	47	Delaware
Hess Midstream Partners GP LP	47	Delaware
Hess (Netherlands) Oil & Gas Holdings C.V.	100	The Netherlands
Hess New Ventures Exploration Limited	100	Cayman Islands
Hess North Dakota Export Logistics L.L.C.	47	Delaware
Hess North Dakota Export Logistics Holdings L.L.C.	47	Delaware

Name of Company	Registrant ownership %	Jurisdiction
Hess North Dakota Export Logistics Operations LP	47	Delaware
Hess North Dakota Pipelines L.L.C.	47	Delaware
Hess North Dakota Pipelines Holdings L.L.C.	47	Delaware
Hess NWE Holdings Limited	100	England & Wales
Hess Offshore Response Company, L.L.C.	100	Delaware
Hess Ohio Developments, L.L.C.	100	Delaware
Hess Ohio Holdings Corporation	100	Delaware
Hess Ohio Sub-Holdings L.L.C.	100	Delaware
Hess Oil and Gas Holdings Inc.	100	Cayman Islands
Hess Oil & Gas Sdn. Bhd.	100	Malaysia
Hess Oil Company of Thailand L.L.C.	100	Texas
Hess Oil Company of Thailand (JDA) Limited	100	Cayman Islands
Hess Services UK Limited	100	England & Wales
Hess Shenzi L.L.C.	100	Delaware
Hess Stampede L.L.C.	100	Delaware
Hess Suriname Exploration Limited	100	Cayman Islands
Hess Tank Cars L.L.C.	47	Delaware
Hess Tank Cars II L.L.C.	47	Delaware
Hess Tank Cars Holdings II L.L.C.	47	Delaware
Hess TGP Finance Company L.L.C.	47	Delaware
Hess TGP Holdings L.L.C.	47	Delaware
Hess TGP Operations LP	47	Delaware
Hess Tioga Gas Plant L.L.C.	47	Delaware
Hess Trading Corporation	100	Delaware
Hess Tubular Bells L.L.C.	100	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 47 subsidiary holding companies (18 domestic and 29 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, and

(7) Registration Statement (Form S-3 No. 333-223279) of Hess Corporation;

of our reports dated February 20, 2020, 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, 2019.

/s/ Ernst & Young LLP
New York, New York
February 20, 2020

Exhibit 23(2)

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

February 20, 2020

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 5, 2020, containing our opinion on the estimated proved reserves, as of December 31, 2019, 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, 2019. 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. 333 223-279) and Form S-8 (No. 333-43569, No. 333-150992, No. 333-167076, No. 333-181704, No. 333-204929, and No. 333-219113).

Very truly yours,

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

Date: February 20, 2020

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 /s/ John P. Rielly
John P. Rielly
Senior Vice President and
Chief Financial Officer

Date: February 20, 2020

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, 2019 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 /s/ John B. Hess
John B. Hess
Chief Executive Officer

Date: February 20, 2020

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.

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, 2019 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, John P. Rielly, Senior 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
Senior Vice President and
Chief Financial Officer

Date: February 20, 2020

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 5, 2020

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, 2019, of the net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain selected 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 5, 2020. Hess has represented to us that these properties account for approximately 80.0 percent on a net equivalent barrel basis of Hess' net proved reserves, as of December 31, 2019, 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 Securities and Exchange Commission (SEC) of the United States. We have reviewed information provided to us by Hess that it represents to be Hess' estimates of the net reserves, as of December 31, 2019, 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, 2019. 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 in which Hess has represented that it holds an interest 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 operating 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 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 of the properties 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 and operating 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 31, 2019, 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 only through August 2019. Estimated cumulative production, as of December 31, 2019, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 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 fuel gas and marketable 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 is that portion of the gas consumed in field operations. Gas reserves estimated herein are reported as marketable gas; therefore, fuel gas is included as reserves. Gas reserves estimated herein 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 reserves included in this report are expressed in billions of cubic feet (109ft3).

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. This conversion factor was provided by Hess.

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 12-month average price (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 arrangements. The 12-month average reference prices used were U.S.$55.73 per barrel for West Texas Intermediate and U.S.$62.54 per barrel for Brent. Hess supplied appropriate differentials by field to the relevant reference prices and the prices were held constant thereafter. The volume-weighted average oil and condensate price for the fields evaluated was U.S.$56.07 per barrel.

NGL Prices

Hess has represented that the NGL prices were based on a 12 month average 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 arrangements. These prices were held constant over the lives of the properties. The volume-weighted average NGL price for the fields evaluated was U.S.$12.04 per barrel.

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 arrangements. The 12-month average reference price for NYMEX was U.S.$2.54 per thousand cubic feet and the UK International Petroleum Exchange reference price was U.S.$4.97 per million Btu. The gas prices were adjusted for each property using differentials to the NYMEX or UK International Petroleum Exchange reference prices furnished by Hess and held constant thereafter. The volume-weighted average gas price for the fields evaluated was U.S.$3.47 per thousand cubic feet.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Hess and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2019 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 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, and 1202(a) (1), (2), (3), (4), (8) 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

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, 2019, attributable to these properties, which represent 80.0 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, 2019			
	Oil and Condensate (106bbl)	**NGL (106bbl)**	**Marketable Gas (109ft3)**	**Oil Equivalent (106boe)**
United States	502	168	677	783
Europe	40	0	81	54
Asia and Other	6	1	688	121
Total	**548**	**169**	**1,446**	**958**

Notes:

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. Totals may vary due to rounding.
3. Net proved fuel gas reserves included as a portion of marketable gas reserves were estimated to be 149 $10^9 ft^3$.

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 less than 1 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, 2019, 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. Foreign oil-producing countries, including members of the Organization of Petroleum Exporting Countries (OPEC), may impose production quotas which limit the supply of oil that can be produced. Generally, these production quotas affect the timing of production, rather than the total volume of oil or gas reserves estimated.

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, 2019, 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,

/s/ DeGolyer and MacNaughton
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Thomas C. Pence, P.E.
Thomas C. Pence, P.E.
Senior Vice President
DeGolyer and MacNaughton

[SEAL]

CERTIFICATE of QUALIFICATION

I, Thomas C. Pence, 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 a Senior Vice President of DeGolyer and MacNaughton, which firm did prepare the report of third party dated February 5, 2020, on the proved reserves evaluation of certain properties attributable to Hess Corporation, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.

2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in 1982; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers and that I have in excess of 37 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Thomas C. Pence, P.E.

Thomas C. Pence, P.E.
Senior Vice President
DeGolyer and MacNaughton

[SEAL]