HESS CORP
Form 10-K
February 21, 2019

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, 2018

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, N.Y.	10036
(Address of principal executive offices)	(Zip Code)

(Registrant's telephone number, including area code, is (212) 997-8500)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock (par value $1.00)	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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or 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 $17,510,000,000, computed using the outstanding common shares and closing market price on June 29, 2018, the last business day of the Registrant's most recently completed second fiscal quarter.

At January 31, 2019, there were 303,034,262 shares of Common Stock outstanding.

Part III is incorporated by reference from the Proxy Statement for the 2019 annual meeting of stockholders.

HESS CORPORATION

Form 10-K

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Unless the context indicates otherwise, references to “Hess”, the “Corporation”, the “Company”, “Registrant”, “we”, “us”, “ou “its” refer to the consolidated business operations of Hess Corporation and its subsidiaries.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain sections in this Annual Report on Form 10-K, including information incorporated by reference herein, and those made under the captions Business and Properties, Management’s Discussion and Analysis of Financial Condition and Results of Operations and Quantitative and Qualitative Disclosures about Market Risk contain “forward-looking” statements, as defined under the Private Securities Litigation Reform Act of 1995. Generally, the words “anticipate,” “estimate,” “expect,” “forecast,” “guidance,” “could,” “may,” “should,” “would,” “believe,” “intend,” “project,” “plan,” “predi similar expressions identify forward-looking statements, which generally are not historical in nature. Forward-looking statements related to our operations 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. As and when made, we believe that these forward-looking statements are reasonable. However, given these 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. Risk factors that could materially impact future actual results are discussed under Item 1A. Risk Factors within this document.

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 or dry well – 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 – Fractionation is the 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 acreage – 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.

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.

NGLs or Natural gas liquids – Naturally occurring substances that are separated and produced by fractionating natural gas, including ethane, butane, isobutane, propane and natural gasoline. NGLs 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.

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

Production entitlement – The share of gross production the Corporation is entitled to receive under the terms of a production sharing contract.

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

Proved 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 drill for and produce oil and gas on the relevant acreage and requires the owner to pay a share of the costs of drilling and production operations.

PART I

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, natural gas liquids, and natural gas with production operations located primarily in the United States (U.S.), Denmark, the Malaysia/Thailand Joint Development Area (JDA) and Malaysia. We conduct exploration activities primarily offshore Guyana, Suriname, Canada and in the U.S. Gulf of Mexico. At the Stabroek Block (Hess 30%), offshore Guyana, we have participated in twelve significant discoveries. The Liza Phase 1 development was sanctioned in 2017 and is expected to startup in early 2020 with production reaching up to 120,000 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 provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGLs; gathering, terminaling, loading and transporting crude oil and NGLs; storing and terminaling propane, and water handling services primarily in the Bakken and Three Forks Shale plays in the Williston Basin area of North Dakota.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for further details.

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, 2018 were $65.55 per barrel for West Texas Intermediate (WTI) (2017: $51.19) and $72.08 per barrel for Brent (2017: $54.87). 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)	
	2018	2017	2018	2017	2018	2017	2018	2017
	(Millions of bbls)		(Millions of bbls)		(Millions of mcf)		(Millions of bbls)	
Developed								
United States	266	239	85	87	432	526	423	414
Europe	38	45	—	—	77	80	51	58
Africa	111	112	—	—	115	117	130	132
Asia and other	4	5	—	—	585	696	102	121
	419	401	85	87	1,209	1,419	706	725
Undeveloped								
United States	235	194	90	84	381	354	389	337
Europe	1	4	—	—	1	12	1	6
Africa	15	16	—	—	13	7	17	17
Asia and other (a)	44	44	—	—	211	149	79	69

	295	258	90	84	606	522	486	429
Total								
United States	501	433	175	171	813	880	812	751
Europe	39	49	—	—	78	92	52	64
Africa	126	128	—	—	128	124	147	149
Asia and other (a)	48	49	—	—	796	845	181	190
	714	659	175	171	1,815	1,941	1,192	1,154

(a) Asia and other includes proved undeveloped reserves in Guyana of 42 million boe at December 31, 2018 (2017: 45 million boe).

Proved undeveloped reserves were 41% of our total proved reserves at December 31, 2018 on a boe basis (2017: 37%). Proved reserves held under production sharing contracts totaled 7% of our crude oil reserves and 44% of our natural gas reserves at December 31, 2018 (2017: 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 82 through 92.

Production

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

	2018	2017	2016
Crude oil - Thousands of barrels			
United States			
Bakken	27,663	24,439	24,881
Other Onshore (a)	389	2,053	3,209
Total Onshore	28,052	26,492	28,090
Offshore	15,026	14,411	16,649
Total United States	43,078	40,903	44,739
Europe			
Norway (a)	—	7,236	8,387
Denmark	2,231	2,988	3,636
	2,231	10,224	12,023
Africa			
Equatorial Guinea (a)	—	9,201	11,898
Libya	6,654	3,542	387
	6,654	12,743	12,285
Asia			
JDA	546	586	616
Malaysia	851	289	152
	1,397	875	768
Total	53,360	64,745	69,815

Natural gas liquids - Thousands of barrels			
United States			
Bakken	10,767	10,107	9,701
Other Onshore (a)	1,647	2,972	4,205
Total Onshore	12,414	13,079	13,906
Offshore	1,703	1,733	1,724
Total United States	14,117	14,812	15,630
Europe - Norway (a)	—	340	408
Total	14,117	15,152	16,038

Natural gas - Thousands of mcf			
United States			
Bakken	25,625	22,621	22,312
Other Onshore (a)	16,167	33,478	48,597
Total Onshore	41,792	56,099	70,909
Offshore	24,452	20,987	23,603
Total United States	66,244	77,086	94,512
Europe			
Norway (a)	—	6,739	8,541

Denmark	2,958	5,124	7,128
	2,958	11,863	15,669
Asia and Other			
JDA	68,477	73,444	68,031
Malaysia (b)	59,995	27,225	13,151
Other	4,288	—	—
	132,760	100,669	81,182
Total	201,962	189,618	191,363
Total Barrels of Oil Equivalent (in millions) (a) (b)	101	112	118

(a) In August 2018, the Corporation sold its Utica Assets, onshore U.S. Utica production averaged 9,000 boepd for calendar year 2018 (2017: 19,000 boepd; 2016: 29,000 boepd). In 2017, the Corporation sold its assets in Equatorial Guinea (November), Norway (December), and the Permian, onshore U.S. (August). Permian production averaged 4,000 boepd for calendar year 2017 (2016: 7,000 boepd).

(b) Includes 6,442 thousand mcf of production for 2018 (2017: 4,256 thousand mcf; 2016: 3,624 thousand mcf) from Block PM301 which is unitized into Block A-18 of the JDA.

E&P Operations

At December 31, 2018, our significant E&P assets included the following:

United States

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

Onshore:

Bakken: At December 31, 2018, we held approximately 543,000 net acres in the Bakken with varying working interest percentages. During 2018, we operated an average of 4.8 rigs, drilled 121 wells, completed 118 wells, and brought 104 wells on production, bringing the total operated production wells to 1,414 by year-end. During 2018, we transitioned from utilizing sliding sleeve completion designs to plug and perf completions. During 2019, we plan to operate six rigs, drill approximately 170 wells and bring approximately 160 wells on production. From 2019, all production wells will use plug and perf completions, which we expect will allow us to increase peak net production to approximately 200,000 boepd by 2021. We forecast net production for full year 2019 to be in the range of 135,000 boepd to 145,000 boepd, compared to production of 117,000 boepd in 2018.

Offshore:

Gulf of Mexico: At December 31, 2018, we held approximately 75,000 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, 2018, we held approximately 270,000 net undeveloped acres, of which leases covering approximately 37,000 acres are due to expire in the next three years.

Production from the Baldpate, Conger, Llano, and Penn State Fields were shut-in following a fire at the third-party operated Enchilada platform in November 2017. In 2018, production restarted at the Baldpate, Llano, and Penn State Fields in the first quarter, and at the Conger Field in the third quarter. At the Hess operated Stampede Field, production commenced in January 2018. In 2019, we plan to drill one production well and two water injection wells at the Stampede Field, one production well at the Llano Field, and one exploration well at the Esox prospect which, if successful, can be tied back into production facilities at the Tubular Bells Field.

Asia

Malaysia/Thailand Joint Development Area (JDA): At the Carigali Hess operated offshore Block A-18 in the Gulf of Thailand (Hess 50%), no drilling is planned for 2019 as contracted volumes are expected to be met from the booster compression project that came online in 2016.

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 our 50% interest in Block PM302 located in the North Malay Basin (NMB), offshore Peninsular Malaysia. Production from full-field development commenced in July 2017. In 2019, we plan to continue the drilling program and development activities.

Europe

Denmark: Production comes from our operated interest in the South Arne Field (Hess 62%). In 2018, we decided to retain our interest in the field after offers received in a previously announced sale process did not meet our value expectations. During 2019, we plan to drill an exploration well on License 06/16, located approximately 19 miles from South Arne.

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 20,000 boepd in 2018, 10,000 boepd in 2017, and 1,000 boepd in 2016. Production was shut-in by the operator for extended periods in 2016 due to force majeure caused by civil unrest. The Company's net investment in Libya was approximately $55 million at December 31, 2018.

Other Non-Producing Countries

Guyana: At the Stabroek Block (Hess 30%), which covers approximately 6.6 million acres offshore Guyana, the operator Esso Exploration and Production Guyana Limited has made twelve significant discoveries to date. The first phase of the Liza Field development, which was sanctioned in 2017, is expected to begin producing oil by early 2020. Phase 1 will use the Liza Destiny FPSO to produce up to 120,000 gross bopd. Drilling of development wells in the Liza Field is continuing, subsea equipment is being prepared for installation, and the topside facilities modules have been installed on the Liza Destiny FPSO in Singapore, which is expected to arrive offshore Guyana in the third quarter of 2019. Preparations are also underway for the installation of subsea umbilicals, risers and flowlines at the Liza Field in the spring of 2019.

Phase 2 of the Liza Field development is expected to start production by mid-2022. Pending government and regulatory approvals, project sanction for Phase 2 is expected by the operator in the first quarter of 2019 and will include a second FPSO vessel designed to produce up to 220,000 gross bopd. Project sanction for a third phase of development at the Payara Field is expected in 2019 with first production expected to start up as early as 2023. In addition to the first three phases, development planning is underway for additional FPSOs. The ultimate sizing and timing will be a function of further exploration and appraisal drilling.

The operator is currently utilizing three drillships on the block. The Stena Carron and the Noble Tom Madden, which arrived in the third quarter of 2018, are involved in exploration and appraisal drilling. The Noble Bob Douglas is drilling development wells for Liza Phase 1. In 2018, the following explorations wells were drilled on the Stabroek Block (in chronological order):

Ranger-1: The well, located approximately 60 miles northwest of the Liza discovery, encountered approximately 230 feet of high-quality, oil-bearing carbonate reservoir.

Pacora-1: The well encountered approximately 65 feet of high-quality, oil-bearing sandstone reservoir, and is located approximately four miles west of the Payara-1 well, which was drilled in 2017. The operator plans to integrate this discovery into the Payara Field development.

Liza-5: The well encountered 77 feet of high-quality, oil-bearing sandstone reservoir and is located approximately six miles northwest of the Liza-1 well, which was drilled in 2016.

Sorubim-1: The well did not encounter commercial quantities of hydrocarbons.

Longtail-1: The well encountered approximately 256 feet of high-quality, oil-bearing sandstone reservoir and is located approximately five miles west of the Turbot-1 well, which was drilled in 2017.

Hammerhead-1: The well encountered approximately 197 feet of high-quality, oil-bearing sandstone reservoir and is located approximately 13 miles to the southwest of the Liza-1 well.

Pluma-1: The well encountered approximately 121 feet of high-quality, hydrocarbon-bearing sandstone reservoir and represents the tenth discovery on the Block. The well is located approximately 17 miles south of the Turbot-1 well.

In February 2019, the operator announced the eleventh and twelfth discoveries on the Stabroek Block at the Tilapia-1 and Haimara-1 wells. The Tilapia-1 well encountered approximately 305 feet of high-quality, oil-bearing sandstone reservoir, and is located approximately three miles west of the Longtail-1 well. 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.

In 2019, additional drilling is planned, including appraisal of the Hammerhead, Ranger and Turbot discoveries, as well as a wider exploration program that will target additional prospects and play types on the 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, expects to complete a 2D seismic shoot in 2019.

Suriname: We hold a 33% non-operated participating interest in Block 42, offshore Suriname. In 2018, the operator, Kosmos Energy Ltd., completed drilling operations on the Pontoenoe-1 exploration well. Commercial quantities of hydrocarbons were not discovered and well results will be integrated into the ongoing evaluation for future exploration on the block. We also hold a 33% non-operated participating interest in Block 59, offshore Suriname, where the operator ExxonMobil Exploration and Production Suriname B.V. commenced a seismic program in 2018.

Canada: We hold a 50% participating interest in four exploration licenses offshore Nova Scotia. In 2018, the operator, BP Canada, completed drilling of the Aspy exploration well, which did not encounter commercial quantities of hydrocarbons. In January 2019, the partnership relinquished 50% of the Nova Scotia acreage in accordance with the license agreement timeline. The retained acreage of approximately 1.75 million gross acres remains under evaluation. We also hold a 25% participating interest in three BP Canada operated exploration licenses offshore Newfoundland.

Sales Commitments

We have certain long-term contracts with fixed minimum sales volume commitments for natural gas and NGLs 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 950 billion cubic feet of natural gas. We also have NGLs minimum delivery commitments, primarily in the Bakken through 2023, of approximately 10 million barrels per year, or approximately 55 million barrels 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 and projected third-party supply.

Selling Prices and Production Costs

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

	2018	2017	2016
Average selling prices (a)			
Crude oil - per barrel (including hedging)			
United States			
Onshore	$56.90	$46.04	$36.92
Offshore	62.02	47.34	37.47
Total United States	58.69	46.50	37.13
Europe (b)	70.08	55.03	43.33
Africa	69.64	53.17	41.88
Asia	70.42	56.99	42.98
Worldwide	60.77	49.23	39.20
Crude oil - per barrel (excluding hedging)			
United States			
Onshore	$60.64	$46.76	$36.92
Offshore	65.73	48.15	37.47
Total United States	62.41	47.25	37.13
Europe (b)	70.08	55.14	43.33
Africa	69.64	53.25	41.88
Asia	70.42	56.99	42.98
Worldwide	63.80	49.75	39.20
Natural gas liquids - per barrel			
United States			
Onshore	$21.29	$17.67	$9.18
Offshore	25.58	21.34	13.96
Total United States	21.81	18.10	9.71
Europe (b)	—	29.04	19.48
Worldwide	21.81	18.35	9.95
Natural gas - per mcf			
United States			
Onshore	$2.29	$1.96	$1.48
Offshore	2.68	2.22	1.99
Total United States	2.43	2.03	1.61
Europe (b)	3.61	4.42	3.97
Asia and other	5.07	4.27	5.31
Worldwide	4.18	3.37	3.37
Average production (lifting) costs per barrel of oil equivalent produced (c)			
United States			
Onshore (d)	$22.34	$19.64	$18.40
Offshore	13.80	11.89	18.88
Total United States	19.74	17.42	18.54
Europe (b)	26.23	21.95	21.28
Africa	4.42	14.40	20.53
Asia and other	6.16	7.83	11.91

Worldwide	15.73	16.07	18.29

(a) Includes inter company transfers valued at approximate market prices, primarily onshore U.S., which include certain processing and distribution fees.

(b) In 2017, we sold our assets in Norway. See Note 3, Dispositions in the Notes to Consolidated Financial Statements. The average selling prices in Norway for 2016 were $43.32 per barrel for crude oil (including hedging), $43.32 per barrel for crude oil (excluding hedging), $19.48 per barrel for NGLs and $5.22 per mcf for natural gas. The average production (lifting) costs in Norway were $24.70 per boe in 2016.

(c) Production (lifting) costs consist of amounts incurred to operate and maintain our producing oil and gas wells, related equipment and facilities and transportation costs, including Midstream tariff expense. Lifting costs do not include costs of finding and developing proved oil and gas reserves, production and severance taxes, or the costs of related general and administrative expenses, interest expense and income taxes.

(d) Includes Midstream tariff expense of $13.69 per boe in 2018 (2017: $11.10 per boe; 2016: $9.24 per boe).

Gross and Net Undeveloped Acreage

At December 31, 2018, gross and net undeveloped acreage amounted to:

	Undeveloped Acreage (a)	
	Gross	Net
	(In thousands)	
United States	436	383
South America	14,332	3,943
Europe	169	91
Africa	3,334	272
Asia and other (b)	6,350	2,755
Total (c)	24,621	7,444

(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, 2018, 26% of our net undeveloped acreage is scheduled to expire during the next three years pending results of exploration activities. In addition, we relinquished 1.75 million gross acres (0.9 million net acres) offshore Nova Scotia, Canada in January 2019.

Gross and Net Developed Acreage, and Productive Wells

At December 31, 2018 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	953	554	2,693	1,281	29	21
Europe	23	14	19	12	—	—
Africa	9,564	782	1,032	84	9	1
Asia and other	452	226	—	—	118	60
Total	10,992	1,576	3,744	1,377	156	82

(a) Includes multiple completion wells (wells producing from different formations in the same bore hole) totaling 105 gross wells and 61 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		
	2018	2017	2016	2018	2017	2016
Productive wells						
United States	—	—	—	92	65	83

Europe	—	—	—	—	1	1
Asia and other	4	2	1	1	1	—
	4	2	1	93	67	84
Dry holes						
United States	—	—	1	—	—	—
Africa (a)	—	—	—	—	—	—
Asia and other (b)	2	—	1	—	—	—
	2	—	2	—	—	—
Total	6	2	3	93	67	84

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

(b) In 2016, we expensed 18 wells relating to our Equus natural gas project, offshore Australia, which were drilled in prior years.

Number of Wells in the Process of Being Drilled

At December 31, 2018, the number of wells in the process of drilling amounted to:

	Gross Wells	Net Wells
United States	112	35
Asia and other	11	4
Total	123	39

Midstream

The Midstream operating segment provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGLs; gathering, terminaling, loading and transporting crude oil and NGLs; storing and terminaling propane, and water handling services primarily in the Bakken and Three Forks Shale plays in the Williston Basin area of North Dakota. In July 2015, we sold a 50% interest in Hess Infrastructure Partners LP (HIP) to Global Infrastructure Partners (GIP) for net cash consideration of approximately $2.6 billion. In April 2017, Hess Midstream Partners LP (the “Partnership”), sold 16,997,000 common units representing limited partner interests at a price of $23 per unit in an initial public offering (IPO) for net proceeds of $365.5 million, of which $350 million was distributed equally to Hess Corporation and GIP.

At December 31, 2018, Hess Corporation and GIP each owned a direct 33.75% limited partner interest in the Partnership and a 50% indirect ownership interest through HIP in the Partnership’s general partner, which has a 2% economic interest in the Partnership plus incentive distribution rights. The public unit holders own a 30.5% limited partner interest in the Partnership. In turn, the Partnership owns an approximate 20% controlling interest in the operating companies that comprise our midstream joint venture, while HIP, the 50/50 joint venture between Hess Corporation and GIP, owns the remaining 80%.

The Partnership, HIP and its affiliates, and other minor water handling services wholly-owned by Hess comprise the Midstream operating segment, which currently generates substantially all of its revenues under long-term, fee-based agreements with our E&P operating segment but intends to pursue additional throughput volumes from third-parties in the Williston Basin area. We operate the Midstream assets under various operational and administrative services agreements. In December 2018, we entered into a Memorandum of Understanding with HIP to sell HIP our water handling business for $225 million in cash, subject to customary adjustments. The parties expect to execute definitive agreements and close the transaction in the first quarter of 2019, subject to receipt of regulatory approvals.

At December 31, 2018, 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 and third-party pipeline facilities. This gathering system consists of approximately 1,200 miles of high and low pressure natural gas and NGL gathering pipelines with a current capacity of up to approximately 370 mmcfd, including an aggregate compression capacity of approximately 190 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 400 miles of crude oil gathering pipelines with a current capacity of up to approximately 160,000 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.
- Little Missouri 4: A natural gas processing plant under construction in McKenzie County, North Dakota, with expected processing capacity of approximately 200 mmcfd. The operator, Targa Resources Corp., estimates the plant will be in service in the second quarter of 2019. The Partnership owns a 50% interest in Little Missouri 4 through a joint venture with Targa Resources Corp. and will be entitled to half of the plant’s processing capacity when

completed.

- 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. In 2018, HIP sold all its remaining older specification crude oil rail cars.
- 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.
- Water assets: A produced water gathering system located primarily in McKenzie, Williams and Mountrail Counties, North Dakota, consisting of approximately 150 miles of water gathering pipelines.

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), Subsea Well Intervention Service (SWIS) 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 $1.11 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 $15 million in 2018 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.

Number of Employees

At December 31, 2018, we had 1,708 employees.

Website Access to Our Reports

We make available free of charge through our website at 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, and Corporate Governance and Nominating 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, NGLs 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, NGLs 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 or inability 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, NGLs and natural gas, political conditions and events (including instability, changes in governments, armed conflict or economic sanctions) around the world and in particular in crude oil or natural gas producing regions, the cost of exploring for, developing and producing crude oil, NGLs 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, NGLs and natural gas. Average prices for 2018 were $64.90 per barrel for WTI (2017: $50.85; 2016: $43.47) and $71.69 per barrel for Brent (2017: $54.74; 2016: $45.13). 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.

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. Reserve replacement can also be achieved through acquisition. Similar risks, however, may be encountered in the production of oil and gas on properties acquired from others. In addition to the technical risks to reserve replacement, replacing reserves and developing future production is 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 have the effect of reducing capital available for exploration and development activity and may render certain development projects uneconomic or delay their completion and may 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 2016, relative to preceding years, resulting in reductions to our reported proved reserves. In contrast, crude oil prices improved somewhat in 2017 and 2018 resulting in increases to our reported proved reserves. If crude oil prices in 2019 average below prices used to determine proved reserves at December 31, 2018, 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.

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. 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, anti-bribery or anti-corruption laws, as well as other political developments may affect our operations and financial results.

We have substantial capital requirements, and we may not be able to obtain needed financing on satisfactory terms, if at all. The exploration, development and production of crude oil and natural gas involves 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, or at all. 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.

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 the operations of the oil and gas industry.

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, like those of the industry, 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 and natural resource damages or 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 and the oil and gas industry in general. 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 initiatives may result in significant operational changes and expenditures, reduced demand for our products and adversely affect our business. We recognize that climate change is a global environmental concern. Continuing political and social attention to the issue of climate change 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. Regulatory initiatives to reduce the use of these fuels may reduce demand for crude oil and other hydrocarbons and have an adverse effect on our sales volumes, revenues and margins. The imposition and enforcement of stringent greenhouse gas emissions reduction targets could severely and adversely impact the oil and gas industry and significantly reduce the value of our business. Furthermore, increasing attention to climate change risks 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.

Catastrophic events, whether naturally occurring or man made, may materially affect our operations and financial conditions. Our oil and gas operations are subject to unforeseen occurrences which have affected us from time to time and which may damage or destroy assets, interrupt operations and have other significant adverse effects. Examples of catastrophic events include hurricanes, fires, explosions, blowouts, pipeline interruptions and ruptures, severe weather, geological events, labor disputes 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.

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 agencies, timely access to necessary equipment, availability of necessary personnel, construction delays, unfavorable weather conditions and equipment failures. This may lead to delays and differences between estimated and actual timing of critical events. 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. These consequences may impact our ability to run our operations and to deliver projects on time with the potential for material negative economic consequences.

We manage commodity price and other risks through our risk management function 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 additional 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 master limited partnership, Hess Midstream Partners LP. The responsibilities associated with being a general partner expose us to a broader range of legal liabilities. Our control of Hess Midstream Partners LP bestows upon us additional fiduciary duties including, but not limited to, the obligations associated with managing potential conflicts of interests, additional reporting requirements from the Securities and Exchange Commission and the provision of tax information to unit holders of Hess Midstream Partners LP. 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 Company may materially impact our business and operations. Computers and telecommunication systems are used to conduct our exploration, development and production activities and have become an integral part of our business. We use these systems to analyze and store financial and operating data and to communicate within our company 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 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, a disruption, failure or a cyber breach of these operating systems, or of the networks and infrastructure on which they rely 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, 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 also agreed with 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 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. The remedy 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. EPA has estimated that this remedy will cost $506 million; however, the ultimate costs that will be incurred in connection with the design and implementation of the remedy remain uncertain. Our alleged liability derives from our former ownership and operation of a fuel oil terminal and connected ship-building and repair facility adjacent to the Canal. We indicated to EPA that we would comply with the Administrative Order and are currently contributing funding for the Remedial Design based on an interim allocation of costs among the parties. At the same time, we are participating in an allocation process whereby a neutral expert selected by the parties will determine the final shares of the Remedial Design costs to be paid by each of the participants.

On September 28, 2017, we received a general notice letter and offer to settle from the U.S. Environmental Protection Agency relating to Superfund claims for the Ector Drum, Inc. Superfund Site in Odessa, Texas. The EPA and Texas Commission on Environmental Quality (TCEQ) took clean-up and response action at the site commencing in 2014 and concluded in December 2015. The site was determined to have improperly stored industrial waste, including drums with oily liquids. The total clean-up cost incurred by the EPA was approximately $3.5 million. We were invited to negotiate a voluntary settlement for our purported share of the clean-up costs. Our share, if any, is undetermined.

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 certain sites, such as those discussed above, the EPA's claims or assertions of liability against us relating to these sites have not been fully developed. With respect to the remaining sites, the EPA's claims have been settled, or a proposed 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 the aforementioned proceedings is not expected to have a material adverse effect on our financial condition, results of operations or cash flows.

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

Our common stock is traded principally on the New York Stock Exchange (ticker symbol: HES).

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 13 oil and gas peer companies, including us as disclosed in our 2018 Proxy Statement.

Comparison of Five Year Shareholder Returns

Years Ended December 31,

Holders

At January 31, 2019, there were 3,100 stockholders (based on the number of holders of record) who owned a total of 303,034,262 shares of common stock.

Dividends

In 2018, 2017 and 2016, cash dividends on common stock totaled $1.00 per share per year ($0.25 per quarter).

Share Repurchase Activities

Our share repurchases activities for the year ended December 31, 2018, were as follows:

2018	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 (d)	Maximum Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs (e) (In millions)
January	607,771	$ 52.30	607,771	$ 998
February	3,670,578	45.76	3,670,578	830
March	3,748,598	48.57	3,708,888	1,650
April (c)	8,039,878	58.49	8,039,878	1,150
May	—	—	—	1,150
June	508,742	58.49	508,742	1,150
July (c)	2,412,545	63.98	2,412,545	950
August	729,203	63.97	729,203	949
September	699,004	70.10	699,004	900
October	505,740	63.27	505,740	868
November	2,130,582	56.79	2,130,582	747
December	2,145,786	45.21	2,145,786	650
Total for 2018	25,198,427	$ 54.84	25,158,717	

(a) Repurchased in open market transactions. The average price paid per share was inclusive of transaction fees.

(b) Includes 39,710 common shares repurchased in March, all of which were subsequently granted to Directors in accordance with the Non-Employee Directors' Stock Award Plan.

(c) In April 2018, we entered into an accelerated share repurchase program (ASR) with a financial institution to repurchase $500 million of our common stock, in which we received an initial delivery of approximately 8 million shares and upon completion of this transaction in June, we received an additional delivery of approximately 0.5 million shares of our common stock. In July 2018, we entered into an ASR with a financial institution to repurchase $200 million of our common stock, in which we received an initial delivery of approximately 2.4 million shares and upon completion of this transaction in August, we received an additional delivery of approximately 0.7 million shares of our common stock. The transaction price for each ASR was determined by the volume-weighted average price of the shares during the term less a negotiated discount.

(d) Since initiation of the buyback program in August 2013, total shares repurchased through December 31, 2018 amounted to 91.9 million at a total cost of $6.85 billion including transaction fees.

(e) 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, 2018.

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	5,170,079	(a)	$ 61.91	19,036,450	(b)
Equity compensation plans not approved by security holders (c)	—		—	—	

(a) This amount includes 5,170,079 shares of common stock issuable upon exercise of outstanding stock options. This amount excludes 1,063,118 performance share units (PSU) 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 2,881,204 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, performance share units 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:

	2018	2017	2016	2015	2014
	(In millions, except per share amounts)				
Income Statement Selected Financial Data					
Sales and other operating revenues					
Crude oil (a)	$4,960	$4,239	$3,639	$5,259	$9,058
Natural gas liquids (a)	533	457	264	244	397
Natural gas (a)	965	750	766	1,052	1,247
Other operating revenues (b)	(135)	20	93	81	35
Total Sales and other operating revenues	$6,323	$5,466	$4,762	$6,636	$10,737
Income (loss) from continuing operations	$(115)	$(3,941)	$(6,076)	$(2,959)	$1,692
Income (loss) from discontinued operations	—	—	—	(48)	682
Net income (loss)	$(115)	$(3,941)	$(6,076)	$(3,007)	$2,374
Less: Net income (loss) attributable to noncontrolling interests	167	133	56	49	57
Net income (loss) attributable to Hess Corporation	$(282) (d)	$(4,074) (e)	$(6,132) (f)	$(3,056) (g)	$2,317 (h)
Net Income (Loss) Attributable to Hess Corporation Per Common Share:					
Basic:					
Continuing operations	$(1.10)	$(13.12)	$(19.92)	$(10.61)	$5.57
Discontinued operations	—	—	—	(0.17)	2.06
Net income (loss) per share	$(1.10)	$(13.12)	$(19.92)	$(10.78)	$7.63
Diluted:					
Continuing operations	$(1.10)	$(13.12)	$(19.92)	$(10.61)	$5.50
Discontinued operations	—	—	—	(0.17)	2.03
Net income (loss) per share	$(1.10)	$(13.12)	$(19.92)	$(10.78)	$7.53
Balance Sheet Selected Financial Data					
Total assets	$21,433	$23,112	$28,621	$34,157	$38,372
Total debt (c)	$6,672	$6,977	$6,806	$6,592	$5,952
Total equity	$10,888	$12,354	$15,591	$20,401	$22,320
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. See Note 1, Nature of Operations, Basis of Presentation and Summary of Accounting Policies in the Notes to Consolidated Financial Statements.

(c) At December 31, 2018 includes debt from our Midstream operating segment of $981 million that is non-recourse to Hess Corporation (2017: $980 million; 2016: $733 million; 2015: $704 million; 2014: $0).

(d) 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 $91 million income tax benefit primarily relating 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.

(e) 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.

(f) 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.

(g) 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.

(h) Includes after tax income of $1,589 million relating to net gains on asset sales and income from the partial liquidation of last in, first out (LIFO) inventories, partially offset by after tax charges totaling $580 million for dry hole expenses, charges associated with termination of lease contracts, severance and other exit costs, income tax restructuring charges and other charges.

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.

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Overview

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, natural gas liquids, and natural gas with production operations located primarily in the United States (U.S.), Denmark, the Malaysia/Thailand Joint Development Area (JDA) and Malaysia. We conduct exploration activities primarily offshore Guyana, Suriname, Canada and in the U.S. Gulf of Mexico. At the Stabroek Block (Hess 30%), offshore Guyana, we have participated in twelve significant discoveries. The Liza Phase 1 development was sanctioned in 2017 and is expected to startup in early 2020 with production reaching up to 120,000 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 provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGLs; gathering, terminaling, loading and transporting crude oil and NGLs; storing and terminaling propane, and water handling services primarily in the Bakken and Three Forks Shale plays in the Williston Basin area of North Dakota.

In 2018, we completed the sale of our joint venture interests in the Utica shale play in eastern Ohio, onshore U.S., and during 2017 we sold our interests in Equatorial Guinea, Norway and our enhanced oil recovery assets in the Permian Basin, onshore U.S. These sales, which generated total proceeds of approximately $3.5 billion, are consistent with our strategy to high grade our portfolio by divesting lower return, mature assets to invest in higher return assets, primarily in Guyana and the Bakken, and to provide returns to shareholders. During 2018, we repurchased $1.38 billion of common stock (2017: $120 million), repaid debt of $633 million, and paid dividends of $345 million. At December 31, 2018, we had cash and cash equivalents of $2.6 billion excluding Midstream.

Outlook

We project our E&P capital and exploratory expenditures will be approximately $2.9 billion in 2019. Capital investment for our Midstream operations is expected to be approximately $330 million. Oil and gas production in 2019 is forecast to be in the range of 270,000 boepd to 280,000 boepd excluding Libya, up from 248,000 boepd in 2018, excluding Libya and assets sold. We have purchased crude oil put options for calendar year 2019 that establish a WTI monthly floor price of $60 per barrel for 95,000 bopd.

Net cash provided by operating activities was $1,939 million in 2018, compared to $945 million in 2017, while capital expenditures for 2018 and 2017 were $2,180 million and $1,973 million, respectively. Based on current forward strip crude oil prices for 2019, we expect cash flow from operating activities and cash and cash equivalents existing at December 31, 2018 will be sufficient to fund our capital investment program and dividends through the end of 2019.

Consolidated Results

Net loss attributable to Hess Corporation was $282 million in 2018 (2017: $4,074 million; 2016: $6,132 million). Excluding items affecting comparability of earnings between periods summarized on page 26, the adjusted net loss was $176 million in 2018 (2017: $1,401 million; 2016: $1,489 million). Annual production averaged 277,000 boepd in 2018 (2017: 306,000 boepd; 2016: 322,000 boepd). Total proved reserves were 1,192 million boe at December 31, 2018 (2017: 1,154 million boe; 2016: 1,109 million boe).

Significant 2018 Activities

The following is an update of significant E&P activities during 2018:

Producing E&P assets:

- In North Dakota, net production from the Bakken oil shale play averaged 117,000 boepd (2017: 105,000 boepd). During 2018, we operated an average of 4.8 rigs, drilled 121 wells, completed 118 wells, and brought on production 104 wells. During 2018, we transitioned from utilizing sliding sleeve completion designs to plug and perf completions. During 2019, we plan to operate six rigs, drill approximately 170 wells and bring approximately 160 wells on production. From 2019, all production wells will use plug and perf completions, which we expect will allow us to increase peak net production to approximately 200,000 boepd by 2021. We forecast net production for full year 2019 to be in the range of 135,000 boepd to 145,000 boepd.
- In the Gulf of Mexico, net production averaged 57,000 boepd (2017: 54,000 boepd). The increase in production was primarily due to the Stampede and Penn State Fields, partially offset by the impact of downtime from a planned well workover at the Tubular Bells Field, the shutdown at the third-party operated Enchilada platform, and natural field decline. We forecast Gulf of Mexico net production for full year 2019 to be in the range of 65,000 boepd to 70,000 boepd.
    - In the Gulf of Thailand, net production from Block A 18 of the JDA averaged 36,000 boepd for the year (2017: 37,000 boepd), including contribution from unitized acreage in Malaysia, while net production from North Malay Basin averaged 27,000 boepd for the year (2017: 11,000 boepd). Production from the North Malay Basin full-field development project commenced in July 2017. During 2018 we drilled three production wells at North Malay Basin, and plan to continue the drilling program and development activities in 2019.

We forecast Gulf of Thailand net production for full year 2019 to be in the range of 60,000 boepd and 65,000 boepd.

- In Denmark, we announced that we decided to retain our interest in the Hess operated offshore South Arne Field after offers received in a previously announced sale process did not meet our value expectations. During 2019, we plan to drill an exploration well on License 06/16, located approximately 19 miles from South Arne.

Other E&P assets:

- Offshore Guyana, at the Stabroek Block (Hess 30%), the operator, Esso Exploration and Production Guyana Limited progressed the first phase of the Liza Field development, which was sanctioned in 2017. The Liza Phase 1 development, which is expected to begin producing oil by early 2020 will use the Liza Destiny FPSO to produce up to 120,000 gross bopd. Drilling of development wells in the Liza Field is continuing, subsea equipment is being prepared for installation, and the topside facilities modules have been installed on the Liza Destiny FPSO in Singapore, which is expected to arrive offshore Guyana in the third quarter of 2019. Preparations are also underway for the installation of subsea umbilicals, risers and flowlines at the Liza Field in the spring of 2019.

Phase 2 of the Liza Field development is expected to start production by mid-2022. Pending government and regulatory approvals, project sanction for Phase 2 is expected by the operator in the first quarter of 2019 and will include a second FPSO vessel designed to produce up to 220,000 gross bopd. Project sanction for a third phase of development at the Payara Field is expected in 2019 with first production expected to start up as early as 2023. In addition to the first three phases, development planning is underway for additional FPSOs. The ultimate sizing and timing will be a function of further exploration and appraisal drilling.

The operator is currently utilizing three drillships on the block. The Stena Carron and the Noble Tom Madden, which arrived in the third quarter of 2018, are involved in exploration and appraisal drilling. The Noble Bob Douglas is drilling development wells for Liza Phase 1. In 2018, the following explorations wells were drilled on the Stabroek Block (in chronological order):

Ranger-1: The well, located approximately 60 miles northwest of the Liza discovery, encountered approximately 230 feet of high-quality, oil-bearing carbonate reservoir.

Pacora-1: The well encountered approximately 65 feet of high-quality, oil-bearing sandstone reservoir, and is located approximately four miles west of the Payara-1 well, which was drilled in 2017. The operator plans to integrate this discovery into the Payara Field development.

Liza-5: The well encountered 77 feet of high-quality, oil-bearing sandstone reservoir and is located approximately six miles northwest of the Liza-1 well, which was drilled in 2016.

Sorubim-1: The well did not encounter commercial quantities of hydrocarbons.

Longtail-1: The well encountered approximately 256 feet of high-quality, oil-bearing sandstone reservoir and is located approximately five miles west of the Turbot-1 well, which was drilled in 2017.

Hammerhead-1: The well encountered approximately 197 feet of high-quality, oil-bearing sandstone reservoir and is located approximately 13 miles to the southwest of the Liza-1 well.

Pluma-1: The well encountered approximately 121 feet of high-quality, hydrocarbon-bearing sandstone reservoir and represents the tenth discovery on the Block. The well is located approximately 17 miles south of the Turbot-1 well.

In February 2019, the operator announced the eleventh and twelfth discoveries on the Stabroek Block at the Tilapia-1 and Haimara-1 wells. The Tilapia-1 well encountered approximately 305 feet of high-quality, oil-bearing sandstone reservoir, and is located approximately three miles west of the Longtail-1 well. 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.

- At Block 42 (Hess - 33%), offshore Suriname, the operator, Kosmos Energy Ltd., completed drilling operations on the Pontoenoe-1 exploration well. Commercial quantities of hydrocarbons were not discovered and well results will be integrated into the ongoing evaluation for future exploration on the block. Total well costs charged to exploration expenses were $33 million.
- In Canada, offshore Nova Scotia (Hess - 50%), the operator, BP Canada, completed drilling of the Aspy exploration well, which did not encounter commercial quantities of hydrocarbons. Total well costs charged to exploration expenses were $120 million.

The following is an update of significant Midstream activities during 2018:

- In December 2018, we entered into a Memorandum of Understanding with HIP to sell HIP our water handling business for $225 million in cash, subject to customary adjustments. The parties expect to execute definitive agreements and close the transaction in the first quarter of 2019, subject to receipt of regulatory approvals.

Liquidity and Capital and Exploratory Expenditures

In 2018, net cash provided by operating activities was $1,939 million (2017: $945 million; 2016: $795 million). At December 31, 2018, consolidated cash and cash equivalents were $2,694 million (2017: $4,847 million), consolidated debt was $6,672 million (2017: $6,977 million), and our consolidated debt to capitalization ratio was 38.0% (2017: 36.1%).

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

	2018	2017	2016
E&P Capital and Exploratory Expenditures			
United States			
Bakken	$967	$624	$429
Other Onshore	43	30	46
Total Onshore	1,010	654	475
Offshore	368	702	735
Total United States	1,378	1,356	1,210
South America	423	242	144
Europe	8	142	65
Asia and other	260	307	452
E&P - Capital and Exploratory Expenditures	$2,069	$2,047	$1,871

Exploration expenses charged to income included in E&P capital and exploratory expenditures above were:

	2018	2017	2016
United States	$106	$90	$93
International	54	105	140
Total Exploration Expenses Charged to Income included above	$160	$195	$233

	2018	2017	2016
Midstream Capital Expenditures			
Midstream - Capital Expenditures (a)	$271	$121	$283

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

In 2019, we project our E&P capital and exploratory expenditures will be approximately $2.9 billion.

Consolidated Results of Operations

Results by Segment:

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

	2018	2017	2016
	(In millions, except per share amounts)		
Net Income (Loss) Attributable to Hess Corporation:			
Exploration and Production	$51	$(3,653)	$(4,964)
Midstream	120	42	42
Corporate, Interest and Other	(453)	(463)	(1,210)
Total	$(282)	$(4,074)	$(6,132)
Net Income (Loss) Attributable to Hess Corporation Per Common Share - Diluted (a)	$(1.10)	$(13.12)	$(19.92)

(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 31 through 35.

	2018	2017	2016
	(In millions)		
Items Affecting Comparability of Earnings Between Periods, After Income Taxes:			
Exploration and Production	$(86)	$(2,609)	$(3,699)
Midstream	—	(34)	(21)
Corporate, Interest and Other	(20)	(30)	(923)
Total	$(106)	$(2,673)	$(4,643)

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

	2018	2017	2016
	(In millions)		
Net income (loss) attributable to Hess Corporation	$(282)	$(4,074)	$(6,132)
Less: Total items affecting comparability of earnings between periods	(106)	(2,673)	(4,643)
Adjusted Net Income (Loss) Attributable to Hess Corporation	$(176)	$(1,401)	$(1,489)

Adjusted net income (loss) attributable to Hess Corporation presented in this report 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. 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. This measure is not, and should not be viewed as, a substitute for U.S. GAAP net income (loss).

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 48. The items in the table below are explained on pages 31 through 35.

	Before Income Taxes		
	2018	2017	2016
	(In millions)		
Total Items Affecting Comparability of Earnings Between Periods, Pre-Tax:			
Sales and other operating revenues	$—	$(22)	$—
Gains (losses) on asset sales, net	24	(98)	27
Operating costs and expenses	(19)	—	(164)
Exploration expenses, including dry holes and lease impairment	(3)	(280)	(1,029)
General and administrative expenses	(130)	(11)	(1)
Loss on debt extinguishment	(53)	—	(148)
Depreciation, depletion and amortization	(16)	(19)	—
Impairment	—	(4,203)	(67)
Total	$(197)	$(4,633)	$(1,382)

Comparison of Results

Exploration and Production

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

	2018	2017	2016
	(In millions)		
Revenues and Non-Operating Income			
Sales and other operating revenues	$6,323	$5,460	$4,755
Gains (losses) on asset sales, net	27	(39)	27
Other, net	53	(1)	16
Total revenues and non-operating income	6,403	5,420	4,798
Costs and Expenses			
Marketing, including purchased oil and gas	1,833	1,335	1,128
Operating costs and expenses	941	1,248	1,658
Production and severance taxes	171	119	101
Midstream tariffs	648	543	497
Exploration expenses, including dry holes and lease impairment	362	507	1,442
General and administrative expenses	258	224	236
Depreciation, depletion and amortization	1,748	2,736	3,113
Impairment	—	4,203	—
Total costs and expenses	5,961		