HESS CORP
Form 10-K
February 21, 2018

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, 2017

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. (Address of principal executive offices)	10036 (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
Depositary Shares, each representing 1/20th interest in a share of 8% Series A Mandatory Convertible Preferred 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 submitted electronically and posted on its Corporate website, if any, every Interactive Data File required to be submitted and posted 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 and post 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. (Check one):

Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company
	(Do not check if a 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 Ex-change 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 $12,290,000,000, computed using the outstanding common shares and closing market price on June 30, 2017, the last business day of the Registrant's most recently completed second fiscal quarter.

At December 31, 2017, there were 315,053,615 shares of Common Stock outstanding.

Part III is incorporated by reference from the Proxy Statement for the 2018 annual meeting of stockholders.

HESS CORPORATION

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Unless the context indicates otherwise, references to "Hess", the "Corporation", "Registrant", "we", "us", "our" and "its" refer 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 as a result 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 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. See the average selling prices in the table on page 9.

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 NGLs 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.

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. Natural gas liquids do not sell at prices equivalent to crude oil. See the average selling prices in the table on page 9.

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 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. The Corporation conducts exploration activities primarily offshore Guyana, Suriname, Canada and in the Gulf of Mexico, including at the Stabroek Block, offshore Guyana, where we have participated in six significant crude oil discoveries and sanctioned the first phase of a multi-phase development project at the Liza Field. During 2017, we sold our interests in Equatorial Guinea, Norway and our enhanced oil recovery assets in the Permian Basin, onshore U.S. The 2017 asset sales of higher cost, mature assets will provide funds toward our future development projects in the Stabroek Block, offshore Guyana. In the fourth quarter of 2017, we announced that we would commence a process to sell our interests in Denmark in 2018.

The Corporation's Midstream operating segment provides fee-based services, including gathering, compressing and processing natural gas and fractionating natural gas liquids (NGLs); gathering, terminaling, loading and transporting crude oil and NGLs; and storing and terminaling propane, primarily in the Bakken and Three Forks Shale plays in the Williston Basin area of North Dakota. On January 1, 2017, the Corporation's interests in a Permian Basin gas plant in West Texas and related CO_2 assets, and water handling assets in North Dakota were transferred from the E&P segment to the Midstream segment as a result of organizational changes to the management of those assets. In the third quarter of 2017, we completed the sale of our Midstream assets in the Permian Basin.

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, 2017 were $51.19 per barrel for WTI (2016: $42.68) and $54.87 per barrel for Brent (2016: $44.45). 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)	
	2017	2016	2017	2016	2017	2016	2017	2016
	(Millions of bbls)		(Millions of bbls)		(Millions of mcf)		(Millions of bbls)	
Developed								
United States	239	245	87	59	526	404	414	371
Europe (a)	45	116	—	3	80	125	58	140
Africa	112	138	—	—	117	132	132	160
Asia and other	5	5	—	—	696	739	121	128
	401	504	87	62	1,419	1,400	725	799
Undeveloped								

United States	194	110	84	27	354	186	337	168
Europe (a)	4	94	—	5	12	95	6	115
Africa	16	24	—	—	7	11	17	26
Asia and other (b)	44	—	—	—	149	5	69	1
	258	228	84	32	522	297	429	310
Total								
United States	433	355	171	86	880	590	751	539
Europe (a)	49	210	—	8	92	220	64	255
Africa	128	162	—	—	124	143	149	186
Asia and other (b)	49	5	—	—	845	744	190	129
	659	732	171	94	1,941	1,697	1,154	1,109

(a) At December 31, 2016, proved reserves in Norway, which were sold in 2017, included crude oil and condensate of 165 million barrels (developed - 75 million barrels; undeveloped - 90 million barrels), natural gas liquids of 8 million barrels (developed - 3 million barrels; undeveloped - 5 million barrels), and natural gas of 160 million mcf (developed - 72 million mcf; undeveloped – 88 million mcf).

(b) Asia and other includes proved undeveloped reserves in Guyana of 45 million boe at December 31, 2017 (2016: 0 million boe).

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Proved undeveloped reserves were 37% of our total proved reserves at December 31, 2017 on a boe basis (2016: 28%). Proved reserves held under production sharing contracts totaled 7% of our crude oil reserves and 44% of our natural gas reserves at December 31, 2017 (2016: 4% and 45%, 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 81 through 91.

Production

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

	2017	2016	2015
Crude oil	(Thousands of barrels)		
United States			
Bakken	24,439	24,881	29,579
Other Onshore (a)	2,053	3,209	3,814
Total Onshore	26,492	28,090	33,393
Offshore	14,411	16,649	20,391
Total United States	40,903	44,739	53,784
Europe			
Norway (a)	7,236	8,387	9,985
Denmark	2,988	3,636	3,981
	10,224	12,023	13,966
Africa			
Equatorial Guinea (a)	9,201	11,898	15,881
Libya	3,542	387	20
Algeria	—	—	2,589
	12,743	12,285	18,490
Asia			
JDA	586	616	613
Malaysia	289	152	196
	875	768	809
Total	64,745	69,815	87,049

	2017	2016	2015
	(Thousands of barrels)		
Natural gas liquids			
United States			
Bakken	10,107	9,701	7,438
Other Onshore (a)	2,972	4,205	4,215
Total Onshore	13,079	13,906	11,653
Offshore	1,733	1,724	2,258
Total United States	14,812	15,630	13,911
Europe - Norway (a)	340	408	499
Total	15,152	16,038	14,410

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	2017	2016	2015
Natural gas	(Thousands of mcf)		
United States			
Bakken	22,621	22,312	23,214
Other Onshore (a)	33,478	48,597	39,929
Total Onshore	56,099	70,909	63,143
Offshore	20,987	23,603	31,751
Total United States	77,086	94,512	94,894
Europe			
Norway (a)	6,739	8,541	9,973
Denmark	5,124	7,128	5,588
	11,863	15,669	15,561
Asia and Other			
JDA	73,444	68,031	83,900
Malaysia (b)	27,225	13,151	18,994
	100,669	81,182	102,894
Total	189,618	191,363	213,349
Total Barrels of Oil Equivalent (in millions) (b)	112	118	137

(a) 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 in 2017 (2016: 7,000 boepd; 2015: 9,000 boepd). See Note 2, Dispositions in the Notes to Consolidated Financial Statements.

(b) Includes 4,256 thousand mcf of production for 2017 (2016: 3,624 thousand mcf; 2015: 5,321 thousand mcf) from Block PM301 which is unitized into Block A-18 of the JDA.

E&P Operations

At December 31, 2017, our significant E&P assets include 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 the Utica Basin of Ohio and from offshore properties in the Gulf of Mexico.

Onshore:

Bakken: At December 31, 2017, we held approximately 554,000 net acres in the Bakken with varying working interest percentages. During 2017, we operated an average of 3.5 rigs, drilled 85 wells, completed 68 wells, and brought 68 wells on production, bringing the total operated production wells to 1,315 by year-end. Drilling and completion costs per operated well averaged $5.6 million in 2017, based on a change in our standard well design during the year to a 60-stage completion with proppant loadings of 140,000 pounds per stage compared to an average well cost of $4.8 million in 2016 using a 50-stage completion with proppant loadings of 70,000 pounds per stage. During 2018, we plan to increase our rig count in the second half of the year to six rigs from four rigs, to drill approximately 120 wells and bring approximately 95 wells on production. In addition, our capital budget for 2018 will fund pad construction in preparation for 2019 drilling. We forecast net production for full year 2018 to be in the range of 115,000 boepd to 120,000 boepd, compared to production of 105,000 boepd in 2017.

Utica: We own a 50% working interest in approximately 37,000 net acres in the wet gas area of the Utica Basin of Ohio. There was no drilling activity in the Utica in 2017. In 2018, we expect to complete and bring on production five previously drilled wells.

Offshore: At December 31, 2017, we held interests in 73 blocks in the deepwater Gulf of Mexico. Our production offshore in the Gulf of Mexico was principally from the Baldpate (Hess 50%), Conger (Hess 38%), Hack Wilson (Hess 25%), Llano (Hess 50%), Penn State (Hess 50%), Shenzi (Hess 28%) and Tubular Bells (Hess 57%) Fields. In addition, we are operator of the Stampede development project (Hess 25%). At December 31, 2017, we held approximately 210,000 net undeveloped acres, of which leases covering approximately 55,000 acres are due to expire in the next three years.

Significant events relating to operations in the Gulf of Mexico during 2017 were as follows:

Producing assets: 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. Prior to the shut-down, net production from these assets was approximately 30,000 boepd. Production at the Baldpate Field restarted in mid-February and is expected to restart at the Penn State Field in the first quarter, at the Llano Field in the second quarter, and at the Conger Field in the third quarter of 2018.

Penn State: At this Hess operated Field, we drilled one production well that was completed in November 2017.

Stampede: At this Hess operated project in the Green Canyon area of the Gulf of Mexico, in 2017 we completed installation of the tension leg platform and subsea equipment, finished drilling and completing three production wells, and received regulatory approval for production operations at the end of the year. In January 2018, we commenced production from the field, which is expected to ramp up over the next 18 months as we continue a drilling program of three additional production wells and four water injection wells.

Europe

Denmark: In 2017, we announced that we plan to commence a process to sell our interest in the Hess operated offshore South Arne Field (Hess 62%) in 2018. Total proved reserves for Denmark were 64 million boe at December 31, 2017.

Africa

Ghana: At the Hess operated offshore Deepwater Tano/Cape Three Points license (Hess 50% license interest), management determined in the fourth quarter of 2017 that it would not develop the previously discovered fields. As a result, we recorded a charge of $280 million to write-off previously capitalized exploration wells and other lease costs. See Capitalized Exploratory Well Costs in Note 5, Property, Plant and Equipment, and Note 24, Subsequent Events in the Notes to Consolidated Financial Statements.

Libya: At the onshore Waha concession in Libya, which includes the Defa, Faregh, Gialo, North Gialo and Belhedan Fields (Hess 8%), production was shut-in by the operator for extended periods in 2016 and 2015 due to force majeure caused by civil unrest. The national oil company of Libya lifted force majeure in September 2016 and production recommenced in October 2016. Net production averaged approximately 10,000 boepd in 2017, 1,000 boepd in 2016, and zero in 2015.

Asia and Other

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 2018 as contracted volumes are expected to be met as a result of 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 Blocks PM302, PM325 and PM326B located in the North Malay Basin (NMB), offshore Peninsular Malaysia, where we operate a multi phase natural gas development project. In July 2017, production of natural gas commenced from the full-field development and net production for 2017 averaged 66 mmcfd, with the planned plateau rate of 165 mmcfd being achieved in the fourth quarter. In 2018, we plan to drill three production wells and progress development activities related to future phases.

Guyana: At the Esso Exploration and Production Guyana Limited operated offshore Stabroek Block (Hess 30% participating interest), the partners sanctioned the first phase of the Liza Field development in 2017. This phase is expected to have a gross capital cost of approximately $3.2 billion for drilling and subsea infrastructure, of which we expect to incur $250 million net in 2018, with first production expected in March 2020. The development plan includes a leased floating production, storage and offloading (FPSO) vessel that will have the capacity to process up to 120,000 barrels of oil per day from 17 wells, including eight producers, six water injectors and three gas injectors. At December 31, 2017, we have proved reserves of 45 million boe, related to Liza Phase 1.

An application for an environmental permit to develop the second phase at Liza has been submitted. The concept for Phase 2 involves the use of a larger FPSO vessel and subsea systems that would have a production capacity of approximately 220,000 bopd, with first production expected by mid-2022. Planning is also underway for a third phase of development with an FPSO vessel at the Payara Field with first production planned for 2023 or 2024. The size of the third ship will depend upon the results of future exploration and appraisal drilling.

In 2017, the following wells were completed on the Stabroek Block (in chronological order):

Payara-1: The well, located approximately 10 miles northwest of the Liza discovery, encountered 95 feet of high-quality, oil bearing sandstone reservoirs.

Snoek-1: The well encountered more than 82 feet of high-quality, oil-bearing sandstone reservoirs and is located approximately 5 miles southeast of the Liza-1 oil discovery.

Liza-4: The well encountered more than 197 feet of high-quality, oil-bearing sandstone reservoirs.

Payara-2: The well encountered 59 feet of high-quality, oil-bearing sandstone reservoirs and confirmed a second large oil field in addition to the Liza Field. The well is located approximately 12 miles northwest from the Liza Phase 1 project.

Turbot-1: The well encountered a reservoir of 75 feet of high-quality, oil-bearing sandstone in the primary objective. The well is located approximately 30 miles to the southeast of the Liza Phase 1 project.

In January 2018, the operator announced a sixth oil discovery at the Ranger prospect. The Ranger-1 well encountered approximately 230 feet of high-quality, oil-bearing carbonate reservoir, and is located approximately 60 miles to the northwest of the Liza Field. In 2018, additional drilling is planned, including appraisal of the Liza, Turbot and Ranger discoveries, as well as a wider exploration program that will target additional prospects and play types on the block. Drilling of the Pacora prospect commenced in January.

Suriname: We hold a 33% non-operated participating interest in the Block 42 contract area, offshore Suriname. The operator, Kosmos Energy Ltd., completed a 6,500-square kilometer 3D seismic shoot in 2017 and expects to drill its first exploration well in 2018. In 2017, we entered into a 33% non-operated participating interest in the Block 59 contract area, offshore Suriname, where the operator, ExxonMobil Exploration and Production Suriname B.V., is planning 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, plans to drill its first exploration well. In addition, in 2017 we were granted 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 natural gas liquids production. At the JDA in the Gulf of Thailand, we have annual minimum net sales commitments of approximately 85 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 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 1.2 trillion cubic feet of natural gas. We also have natural gas liquids minimum delivery commitments, primarily in the Bakken through 2023, of approximately 10 million barrels per year, or approximately 60 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.

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Selling Prices and Production Costs

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

	2017	2016	2015
Average selling prices (a)			
Crude oil - per barrel (including hedging)			
United States			
Onshore	$46.04	$36.92	$42.67
Offshore	47.34	37.47	46.21
Total United States	46.50	37.13	44.01
Europe (b)	55.03	43.33	55.10
Africa	53.17	41.88	53.89
Asia	56.99	42.98	52.74
Worldwide	49.23	39.20	47.85
Crude oil - per barrel (excluding hedging)			
United States			
Onshore	$46.76	$36.92	$41.22
Offshore	48.15	37.47	46.21
Total United States	47.25	37.13	43.11
Europe (b)	55.14	43.33	52.37
Africa	53.25	41.88	51.57
Asia	56.99	42.98	52.74
Worldwide	49.75	39.20	46.37
Natural gas liquids - per barrel			
United States			
Onshore	$17.67	$9.18	$9.18
Offshore	21.34	13.96	14.40
Total United States	18.10	9.71	10.02
Europe (b)	29.04	19.48	24.59
Worldwide	18.35	9.95	10.52
Natural gas - per mcf			
United States			
Onshore	$1.96	$1.48	$1.64
Offshore	2.22	1.99	2.03
Total United States	2.03	1.61	1.77
Europe (b)	4.42	3.97	6.72
Asia	4.27	5.31	5.97
Worldwide	3.37	3.37	4.16
Average production (lifting) costs per barrel of oil equivalent produced (c)			
United States			
Onshore (d)	$19.66	$18.46	$18.57
Offshore	11.89	18.88	7.03
Total United States	17.44	18.58	14.73
Europe (b)	21.95	21.28	23.61
Africa	14.40	20.53	23.12
Asia and other	7.83	11.91	8.34

Worldwide	16.08	18.32	16.12

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

(b) In 2017, we sold our assets in Norway. See Note 2, 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 natural gas liquids and $5.22 per mcf for natural gas (2015: $54.89, $52.15, $24.59 and $8.58, respectively). The average production (lifting) costs in Norway were $24.70 per barrel of oil equivalent in 2016 (2015: $25.81).

(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 $11.10 per boe in 2017 (2016: $9.24 per boe; 2015: $8.52 per boe).

Gross and Net Undeveloped Acreage

At December 31, 2017, gross and net undeveloped acreage amounted to:

	Undeveloped Acreage (a)	
	Gross	Net
	(In thousands)	
United States	412	348
Europe	169	91
Africa	3,831	521
Asia and other	14,845	5,424
Total (b)	19,257	6,384

(a) Includes acreage held under production sharing contracts.

(b) At December 31, 2017, licenses covering approximately 2% of our net undeveloped acreage held are scheduled to expire during the next three years pending the results of exploration activities.

Gross and Net Developed Acreage, and Productive Wells

At December 31, 2017 gross and net developed acreage and productive wells amounted to:

	Developed Acreage Applicable to Productive Wells		Productive Wells (a)			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
	(In thousands)					
United States	1,034	603	2,535	1,251	158	68
Europe	45	23	19	12	—	—
Africa	9,564	782	1,022	83	—	—
Asia and other	452	226	—	—	100	55
Total	11,095	1,634	3,576	1,346	258	123

(a) Includes multiple completion wells (wells producing from different formations in the same bore hole) totaling 106 gross wells and 62 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		
	2017	2016	2015	2017	2016	2015
Productive wells						
United States	—	—	—	65	83	181
Europe	—	—	—	1	1	5
Asia and other	2	1	3	1	—	1
	2	1	3	67	84	187

Dry holes						
United States	—	1	—	—	—	—
Africa (a)	—	—	1	—	—	—
Asia and other (b)	—	1	5	—	—	—
	—	2	6	—	—	—
Total	2	3	9	67	84	187

(a) In 2017, we expensed seven wells in our Deepwater Tano/Cape Three Points block, offshore Ghana, which were drilled in prior years. See Note 5, Property, Plant and Equipment in the Notes to Consolidated Financial Statements.

(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, 2017, the number of wells in the process of drilling amounted to:

	Gross Wells	Net Wells
United States	70	27
Asia and other	2	1
Total	72	28

Midstream

The Midstream operating segment provides fee-based services, including gathering, compressing and processing natural gas and fractionating natural gas liquids (NGLs); gathering, terminaling, loading and transporting crude oil and NGLs; and storing and terminaling propane, 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, 2017, 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, and HIP and its affiliates primarily 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. Beginning January 1, 2017, the Midstream segment included our interest in a Permian gas plant in West Texas and related CO_2 assets, and water handling assets in North Dakota as a result of organizational changes to the management of those assets. In the third quarter of 2017, we completed the sale of our assets in the Permian Basin, including the gas plant in West Texas and related CO_2 assets. The water assets are wholly-owned by the Corporation and are not included in our HIP joint venture.

At December 31, 2017, Midstream assets include 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 345 mmcfd, including an aggregate compression capacity of 174 mmcfd. The system also includes the Hawkeye Gas Facility, which contributes 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 365 miles of crude oil gathering pipelines with a current capacity of up to 161,000 bopd. The system also includes the Hawkeye Oil Facility, which contributes 76,000 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 250 mmcfd and fractionation capacity of 60,000 boepd.
- Mentor Storage Terminal: A propane storage cavern and rail and truck loading and unloading facility located in Mentor, Minnesota, with approximately 328,000 boe of working storage capacity.

- Ramberg Terminal Facility: A crude oil pipeline and truck receipt terminal located in Williams County, North Dakota that is capable of delivering up to 282,000 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 addition, at December 31, 2017, HIP also has 105 older specification crude oil rail cars. In 2016, we recorded an impairment charge against these older specification rail cars, which are not in service. See Note 3, Impairment in Notes to Consolidated Financial Statements.
- 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.

In 2018, the Partnership announced the formation of a 50/50 joint venture with Targa Resources Corp. to construct a new 200 mmcfd gas processing plant south of the Missouri River in McKenzie County, North Dakota, which is expected to be completed in the second half of 2018. The plant is expected to increase the Midstream segment's total processing capacity in the Bakken to 350 mmcfd. As part of this project, HIP will construct new pipeline infrastructure to gather volumes for the new plant. The expected combined project costs attributable to our Midstream segment is $175 million.

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 risk appropriate and are maintained, reviewed and updated as necessary to confirm their accuracy and suitability. Where appropriate, 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 anywhere in the world. 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. These owned 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 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 a number of 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 2017 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, 2017, we had 2,075 employees. In January 2018, we eliminated approximately 300 of these positions. See Note 24, Subsequent Events in Notes to Consolidated Financial Statements.

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, natural gas liquids 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, natural gas liquids 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, natural gas liquids and natural gas, political conditions and events (including instability, changes in governments, or armed conflict) around the world and in particular in crude oil or natural gas producing regions, the cost of exploring for, developing and producing crude oil, natural gas liquids 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, natural gas liquids and natural gas. Average prices for 2017 were $50.85 per barrel for WTI (2016: $43.47; 2015: $48.76) and $54.74 per barrel for Brent (2016: $45.13; 2015: $53.60). 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 significantly in 2015 and to a lesser extent in 2016, relative to preceding years, resulting in reductions to our reported proved reserves. In contrast, crude oil prices improved somewhat in 2017 resulting in increases to our reported proved reserves. If crude oil prices in 2018 average below prices used to determine proved reserves at December 31, 2017, 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, limitations on access to exploration and development opportunities, anti-bribery or anti-corruption laws, as well as other political developments may affect our operations.

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. For example, in 2017, we had a significant net loss and, unless commodity prices are considerably higher through 2018, we are forecasting a net loss for 2018. 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, and the partners with whom we operate, are politically less stable than other areas and partners and may be subject to civil unrest, conflict, insurgency, geographic territorial border disputes, corruption, security risks and labor unrest. Political and civil unrest in North Africa and the Middle East has affected and may affect our operations in these areas as well as oil and gas markets generally. 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 increased likelihood of governmental investigations and private litigation, which could increase our costs or otherwise adversely affect our business. For example, in 2017 certain municipalities in California 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 than we have. The petroleum industry is highly competitive and very capital intensive. We encounter competition from numerous companies in each of our activities, 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. Increased competition for worldwide oil and gas assets could significantly increase the cost of acquiring 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.

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 risks 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 impacts 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 increases involved, limit any potential upside from commodity price increases. As with accounts receivable 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 the 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 and may divert management resource from our other operations.

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, 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 is a defective product and that these parties 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 four remaining active cases, filed by Pennsylvania, Vermont, Rhode Island, and Maryland. In June 2014, the Commonwealth of Pennsylvania and the State of Vermont each filed independent lawsuits alleging that we and all major oil companies with operations in each respective state, have damaged the groundwater in those states by introducing thereto gasoline with MTBE. The Pennsylvania suit has been removed to Federal court and has been forwarded to the existing MTBE multidistrict litigation pending in the Southern District of New York. The suit filed in Vermont is proceeding there in a state court. 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 was filed in state court, but has not been served to date.

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 there are numerous other parties who we expect will share in the cost of remediation and damages and our former terminal did not store or use contaminants which are of the greatest concern in the river sediments and could not have contributed contamination along most of the river's length.

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, TX. 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 are 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). High and low sales prices were as follows:

	2017		2016	
Quarter Ended	High	Low	High	Low
March 31	$64.40	$45.12	$54.83	$32.41
June 30	52.10	39.89	63.76	49.52
September 30	47.68	37.25	61.54	45.37
December 31	48.75	40.26	65.56	46.06

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 2017 Proxy Statement).

Comparison of Five Year Shareholder Returns

Years Ended December 31,

Holders

At December 31, 2017, there were 3,260 stockholders (based on the number of holders of record) who owned a total of 315,053,615 shares of common stock.

Dividends

In 2017, 2016 and 2015, cash dividends on common stock totaled $1.00 per share per year ($0.25 per quarter).

Share Repurchase Activities

Our share repurchase activities for the year ended December 31, 2017, were as follows:

2017	Total Number of Shares Purchased (a) (b)	Average Price Paid per Share (a)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (c)	Maximum Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs (d) (In millions)
January	—	$ —	—	$ 1,150
February	41,070	51.73	—	1,150
March	—	—	—	1,150
April	—	—	—	1,150
May	—	—	—	1,150
June	—	—	—	1,150
July	—	—	—	1,150
August	—	—	—	1,150
September	—	—	—	1,150
October	—	—	—	1,150
November	1,300,300	45.15	1,300,300	1,091
December	1,327,020	46.19	1,327,020	1,030
Total for 2017	2,668,390	$ 45.77	2,627,320	

(a) Repurchased in open market transactions. The average price paid per share was inclusive of transaction fees.
(b) Includes 41,070 common shares repurchased in February, substantially all of which were subsequently granted to Directors in accordance with the Non-Employee Directors' Stock Award Plan.
(c) Since initiation of the buyback program in August 2013, total shares repurchased through December 31, 2017 amounted to 66.74 million at a total cost of $5.5 billion including transaction fees.
(d) In March 2013, we announced that our Board of Directors approved a stock repurchase program that authorized the purchase of common stock up to a value of $4.0 billion. In May 2014, the share repurchase program was increased to $6.5 billion.

Equity Compensation Plans

Following is information related to our equity compensation plans at December 31, 2017.

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	6,482,215	(a)	$ 66.84	20,763,503	(b)
Equity compensation plans not approved by security holders (c)	—		—	—	

(a) This amount includes 6,482,215 shares of common stock issuable upon exercise of outstanding stock options. This amount excludes 1,146,832 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 3,202,323 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 our non-employee directors received in aggregate $2.1 million 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:

	2017	2016	2015	2014	2013
	(In millions, except per share amounts)				
Income Statement Selected Financial Data					
Sales and other operating revenues					
Crude oil	$4,239	$3,639	$5,259	$9,058	$9,998
Natural gas liquids	457	264	244	397	457
Natural gas	750	766	1,052	1,247	1,394
Other operating revenues	20	93	81	35	56
Total Sales and other operating revenues	$5,466	$4,762	$6,636	$10,737	$11,905
Income (loss) from continuing operations	$(3,941)	$(6,076)	$(2,959)	$1,692	$4,036
Income (loss) from discontinued operations	—	—	(48)	682	1,186
Net income (loss)	$(3,941)	$(6,076)	$(3,007)	$2,374	$5,222
Less: Net income (loss) attributable to noncontrolling interests	133	56	49	57	170
Net income (loss) attributable to Hess Corporation	$(4,074) (a)	$(6,132) (b)	$(3,056) (c)	$2,317 (d)	$5,052 (e)
Net Income (Loss) Attributable to Hess Corporation Per Common Share:					
Basic:					
Continuing operations	$(13.12)	$(19.92)	$(10.61)	$5.57	$11.47
Discontinued operations	—	—	(0.17)	2.06	3.54
Net income (loss) per share	$(13.12)	$(19.92)	$(10.78)	$7.63	$15.01
Diluted:					
Continuing operations	$(13.12)	$(19.92)	$(10.61)	$5.50	$11.33
Discontinued operations	—	—	(0.17)	2.03	3.49
Net income (loss) per share	$(13.12)	$(19.92)	$(10.78)	$7.53	$14.82
Balance Sheet Selected Financial Data					
Total assets	$23,112	$28,621	$34,157	$38,372	$42,482
Total debt	$6,977	$6,806	$6,592	$5,952	$5,765
Total equity	$12,354	$15,591	$20,401	$22,320	$24,784
Dividends Per Share					
Dividends per share of common stock	$1.00	$1.00	$1.00	$1.00	$0.70

(a) 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.

(b) 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.

(c) 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.

(d) 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.

(e) Includes after tax income of $4,060 million relating to net gains on asset sales, Denmark's enacted changes to the hydrocarbon income tax law and income from the partial liquidation of LIFO inventories, partially offset by after tax charges totaling $900 million for asset impairment, dry hole expenses, severance and other exit costs, income tax charges, refinery shutdown costs, and other charges.

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

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. The Corporation conducts exploration activities primarily offshore Guyana, Suriname, Canada and in the Gulf of Mexico, including at the Stabroek Block, offshore Guyana, where we have participated in six significant crude oil discoveries and sanctioned the first phase of a multi-phase development project at the Liza Field. During 2017, we sold our interests in Equatorial Guinea, Norway and our enhanced oil recovery assets in the Permian Basin, onshore U.S. The 2017 asset sales of higher cost, mature assets will provide funds toward our future development projects in the Stabroek Block, offshore Guyana. In the fourth quarter of 2017, we announced that we would commence a process to sell our interests in Denmark in 2018. These actions reflect the execution of our strategy to grow our resource base in a capital disciplined manner and to be cash generative at a $50 per barrel Brent oil price post 2020.

The Corporation's Midstream operating segment provides fee-based services, including gathering, compressing and processing natural gas and fractionating natural gas liquids (NGLs); gathering, terminaling, loading and transporting crude oil and NGLs; and storing and terminaling propane, primarily in the Bakken and Three Forks Shale plays in the Williston Basin area of North Dakota. Beginning January 1, 2017, Hess' Midstream segment included our interest in a Permian gas plant in West Texas and related CO_2 assets, and water handling assets in North Dakota as a result of organizational changes to the management of those assets. Prior period information has been recast to conform to the current period presentation. See Note 22, Segment Information in the Notes to Consolidated Financial Statements. In the third quarter of 2017, we completed the sale of our Midstream assets in the Permian Basin. See Note 2, Dispositions in the Notes to Consolidated Financial Statements.

Outlook

The Corporation and its partners have discovered significant crude oil and natural gas resources on the Stabroek Block, offshore Guyana, which will require substantial capital and time to fully develop. As a result of these discovered fields, which are expected to have a lower development cost than other assets in our portfolio, we have changed the priorities of our future investment plans, and have divested of higher cost, mature assets to provide funds toward future development of Guyana. In addition, we have announced plans to reduce debt and repurchase common stock.

We project our E&P capital and exploratory expenditures will be approximately $2.1 billion in 2018, up from $2.0 billion in 2017, reflecting increased activity at the Liza Field development project and a higher rig count in the Bakken, partially offset by lower spend at the Stampede Field and North Malay Basin development projects. Capital expenditures, including equity investments, for our Midstream operations are expected to be approximately $330 million. Oil and gas production in 2018 is forecast to be in the range of 245,000 boepd to 255,000 boepd excluding any contribution from Libya and reflecting an estimated 15,000 boepd reduction due to the extended Enchilada platform shutdown, up from 242,000 boepd in 2017, excluding Libya and assets sold.

Net cash provided by operating activities was $945 million in 2017, compared to $795 million in 2016, while capital expenditures for 2017 and 2016 were $1,973 million and $1,921 million, respectively. Based on current forward strip crude oil prices, we forecast a net operating cash flow deficit (including capital expenditures) in 2018. The Corporation expects to fund its 2018 net operating cash flow deficit (including capital expenditures), reduce debt by $500 million and repurchase $380 million of common stock with existing cash and cash equivalents, which was $4.5

billion at December 31, 2017, excluding Midstream.

Consolidated Results

Net loss attributable to Hess Corporation was $4,074 million in 2017 (2016: $6,132 million; 2015: $3,056 million). Excluding items affecting comparability summarized on page 26, the adjusted net loss was $1,401 million in 2017 (2016: $1,489 million; 2015: $1,113 million). Annual production averaged 306,000 boepd in 2017 (2016: 322,000 boepd; 2015: 375,000 boepd). Total proved reserves were 1,154 million boe at December 31, 2017 (2016: 1,109 million boe; 2015: 1,086 million boe).

Significant 2017 Activities

The following is an update of significant E&P activities during 2017:

Producing E&P assets:

- In North Dakota, net production from the Bakken oil shale play averaged 105,000 boepd (2016: 105,000 boepd). During 2017, we operated an average of 3.5 rigs, drilled 85 wells, completed 68 wells, and brought on production 68 wells, bringing the total operated production wells to 1,315 at December 31, 2017. Drilling and completion costs per operated well averaged $5.6 million in 2017, based on a change in our standard well design during the year to a 60-stage completion with proppant loadings of 140,000 pounds per stage compared to an average well cost of $4.8 million in 2016 using a 50-stage completion with proppant loadings of 70,000 pounds per stage. During 2018, we plan to increase our rig count in the second half of the year from four to six rigs, to drill approximately 120 wells and bring approximately 95 wells on production. In addition, our capital budget for 2018 will fund pad construction in preparation for 2019 drilling. We forecast net production for full year 2018 to be in the range of 115,000 boepd to 120,000 boepd.
- In the Gulf of Mexico, net production averaged 54,000 boepd (2016: 61,000 boepd). The decrease in production was primarily due to a fire at the third-party operated Enchilada platform and natural field decline, partially offset by higher production at the Tubular Bells Field. Prior to the shutdown of the Enchilada platform in November, we were producing approximately 30,000 boepd from the Llano, Conger, Baldpate and Penn State Fields through infrastructure associated with Enchilada. At the Penn State Field, we competed one well in November 2017. In 2018, Gulf of Mexico production is forecast to average approximately 50,000 boepd, which reflects an estimated full year production impact of approximately 15,000 boepd associated with Enchilada.

At the Hess operated Stampede development project in the Green Canyon area of the Gulf of Mexico, in 2017 we completed installation of the tension leg platform and subsea equipment, finished drilling and completing three production wells, and received regulatory approval for production operations at the end of the year. In January 2018, we commenced production from the field, which is expected to ramp up over the next 18 months as we continue a drilling program of three additional production wells and four water injection wells.

- In Block A 18 of the JDA, net production averaged 223 mmcfd (2016: 206 mmcfd), including contribution from unitized acreage in Malaysia, with the increase from prior-year primarily due to the planned shutdown in 2016 to commission the booster compressor project. Production from the JDA is forecast to average approximately 215 mmcfd in 2018.
- In the North Malay Basin (NMB), production of natural gas commenced from the full-field development in July and net production averaged 66 mmcfd for the year (2016: 26 mmcfd). The field achieved the planned plateau rate of 165 mmcfd, and we forecast net production from NMB to average approximately 160 mmcfd in 2018. We plan to drill three production wells in 2018 and progress development activities related to future phases.
- In the Utica shale, net production decreased to 19,000 boepd (2016: 29,000 boepd) due to natural decline following the suspension of drilling activities in the first quarter of 2016. In 2018, we expect to complete and bring on production five previously drilled wells.
- In Libya, net production from the Waha Fields averaged approximately 10,000 boepd (2016: 1,000 boepd), with the increase from prior-year due to the lifting of force majeure by the national oil company of Libya in September 2016.
- We sold our interests in Equatorial Guinea and Norway, and enhanced oil recovery assets in the Permian Basin. See Note 2, Dispositions in the Notes to Consolidated Financial Statements.

Other E&P assets:

- In Guyana, at the Esso Exploration and Production Guyana Limited operated offshore Stabroek Block (Hess 30% participating interest), the partners sanctioned the first phase of the Liza Field development in 2017. This phase is expected to have a gross capital cost of approximately $3.2 billion for drilling and subsea infrastructure, of which we expect to incur $250 million net in 2018, with first production expected in March 2020. The development plan includes a leased floating production, storage and offloading (FPSO) vessel that will have the capacity to process up to 120,000 barrels of oil per day from 17 wells, including eight producers, six water injectors and three gas injectors. An application for an environmental permit to develop the second phase at Liza has been submitted. The concept for Phase 2 involves the use of a larger FPSO vessel and subsea systems that would have a production capacity of approximately 220,000 bopd, with first production expected by mid-2022. Planning is also underway for a third phase of development with an FPSO vessel at the Payara Field with first production planned for 2023 or 2024. The size of the third ship will depend upon the results of future exploration and appraisal drilling.

In 2017, the following wells were drilled on the Stabroek Block (in chronological order):

Payara-1: The well, located approximately 10 miles northwest of the Liza discovery, encountered 95 feet of high-quality, oil bearing sandstone reservoirs.

Snoek-1: The well encountered more than 82 feet of high-quality, oil-bearing sandstone reservoirs and is located approximately 5 miles southeast of the Liza-1 oil discovery.

Liza-4: The well encountered more than 197 feet of high-quality, oil-bearing sandstone reservoirs.

Payara-2: The well encountered 59 feet of high-quality, oil-bearing sandstone reservoirs and confirmed a second large oil field in addition to the Liza Field. The well is located approximately 12 miles northwest from the Liza Phase 1 project.

Turbot-1: The well encountered a reservoir of 75 feet of high-quality, oil-bearing sandstone in the primary objective. The well is located approximately 30 miles to the southeast of the Liza Phase 1 project.

In January 2018, the operator announced a sixth oil discovery at the Ranger prospect. The Ranger-1 well encountered approximately 230 feet of high-quality, oil-bearing carbonate reservoir, and is located approximately 60 miles to the northwest of the Liza Field. In 2018, additional drilling is planned, including appraisal of the Liza, Turbot and Ranger discoveries, as well as a wider exploration program that will target additional prospects and play types on the block. Drilling of the Pacora prospect commenced in January.

- In Ghana, at the Hess operated offshore Deepwater Tano/Cape Three Points license (Hess 50% license interest), management determined in the fourth quarter of 2017 that it would not develop the previously discovered fields. As a result, we recorded a charge of $280 million to write-off previously capitalized exploration wells and other lease costs. See Capitalized Exploratory Well Costs in Note 5, Property, Plant and Equipment, and Note 24, Subsequent Events in the Notes to Consolidated Financial Statements.

The following is an update of significant Midstream activities during 2017:

- In the second quarter, 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 50/50 to Hess Corporation and GIP. See Item 1 and 2. Business and Properties.
- In the fourth quarter, HIP, issued $800 million of 5.625% senior notes, due in February 2026 and concurrently amended its senior unsecured credit facilities. HIP used a portion of the proceeds from the note issuance to repay borrowings under HIP’s credit facilities and to fund a distribution to the partners. The remaining proceeds will be used for general partnership purposes of the joint venture. Under the amended credit facilities, the 5-year Term Loan A facility was reduced to $200 million and the 5-year syndicated revolving credit facility increased to $600 million from $400 million previously, with the maturity of both facilities extended to November 2022. The credit facilities are secured by first-priority perfected liens on substantially all of HIP’s and certain of its wholly-owned subsidiaries’ directly owned assets, including its equity interests in certain subsidiaries, subject to customary exclusions. The 5-year syndicated revolving credit facility is expected to continue to fund the joint venture’s operating activities and capital expenditures.

During 2017, the Midstream segment brought online key strategic projects, including safe and successful start-up of the Hawkeye Gas Facility, the Hawkeye Oil Facility and the Johnson's Corner Header System. These projects have increased the Midstream segment's throughput volumes, customer optionality and system connectivity. Hess Midstream has also recently executed a strategic gas processing joint venture with Targa Resources Corp. that will further support the production growth in the Bakken.

U.S. Tax Cuts and Jobs Act

The enactment of U.S. federal tax reform, commonly referred to as the U.S. Tax Cuts and Jobs Act ("Act"), provided for broad changes to the taxation of both domestic and foreign operations. The provisions of the Act, including its extensive transition rules, are complex and interpretive guidance continues to develop. Final application of the Act to our operations and financial results may differ from that for which we have provisionally provided as of December 31, 2017. Changes could arise as regulatory and interpretive action continues to clarify aspects of the Act and as changes are made to estimates that the Corporation has utilized in calculating the transition impacts.

No U.S. federal tax has been accrued on the deemed repatriation of unremitted earnings of our foreign subsidiaries. A decrease in the U.S. federal corporate tax rate to 21% from 35% resulted in a $1,476 million reduction to our U.S. federal net deferred tax asset as of December 31, 2017, with a corresponding reduction in the previously established U.S. valuation allowance. A deferred tax liability of $110 million no longer meets the recognition criteria with the transition to a territorial regime for U.S. taxation of foreign earnings and has been derecognized, with a corresponding adjustment to the valuation allowance against the U.S. federal net deferred tax asset. Under the transition rules related to the repeal of the alternative minimum tax regime, an alternative minimum tax credit carryforward of $4 million will be refundable if not used to offset regular tax liability. The previously established valuation allowance against this credit carryforward has been released. Consequently, these tax law changes resulted in a net $4 million increase to net deferred tax asset on the balance sheet and benefit to deferred tax expense.

Liquidity and Capital and Exploratory Expenditures

In 2017, net cash provided by operating activities was $945 million (2016: $795 million; 2015: $1,981 million). At December 31, 2017, consolidated cash and cash equivalents were $4,847 million (2016: $2,732 million), consolidated debt was $6,977 million (2016: $6,806 million), and our consolidated debt to capitalization ratio was 36.1% (2016: 30.4%).

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

	2017	2016	2015
E&P Capital and Exploratory Expenditures			
United States			
Bakken	$624	$429	$1,308
Other Onshore	30	46	328
Total Onshore	654	475	1,636
Offshore	702	735	923
Total United States	1,356	1,210	2,559
Europe	142	65	298
Africa	30	10	161
Asia and other	519	586	1,020
E&P - Capital and Exploratory Expenditures	$2,047	$1,871	$4,038

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

	2017	2016	2015
United States	$90	$93	$132

International	105	140	157
Total Exploration Expenses Charged to Income included above	$195	$233	$289

	2017	2016	2015
Midstream Capital Expenditures			
Midstream - Capital Expenditures	$121	$283	$300

In 2018, we plan to incur approximately $2.1 billion on E&P capital and exploratory expenditures, and approximately $330 million on Midstream capital expenditures, including equity investments.

Consolidated Results of Operations

Results Including Items Affecting Comparability of Earnings Between Periods:

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

	2017	2016	2015
	(In millions, except per share amounts)		
Net Income (Loss) Attributable to Hess Corporation:			
Exploration and Production	$(3,653)	$(4,964)	$(2,727)
Midstream	42	42	96
Corporate, Interest and Other	(463)	(1,210)	(377)
Income (loss) from continuing operations	(4,074)	(6,132)	(3,008)
Discontinued operations	—	—	(48)
Total	$(4,074)	$(6,132)	$(3,056)
Net Income (Loss) per Common Share - Diluted (a):			
Continuing operations	$(13.12)	$(19.92)	$(10.61)
Discontinued operations	—	—	(0.17)
Net Income (Loss) Attributable to Hess Corporation Per Common Share - Diluted	$(13.12)	$(19.92)	$(10.78)

(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 36.

	2017	2016	2015
	(In millions)		
Exploration and Production	$(2,609)	$(3,699)	$(1,851)
Midstream	(34)	(21)	—
Corporate, Interest and Other	(30)	(923)	(44)
Discontinued operations	—	—	(48)
Total Items Affecting Comparability of Earnings Between Periods, After-Tax	$(2,673)	$(4,643)	$(1,943)

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

	2017	2016	2015
	(In millions)		
Net income (loss) attributable to Hess Corporation	$(4,074)	$(6,132)	$(3,056)

Less: Total items affecting comparability of earnings between periods	(2,673)	(4,643)	(1,943)
Adjusted Net Income (Loss) Attributable to Hess Corporation	$(1,401)	$(1,489)	$(1,113)

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 pre-tax items affecting comparability of income (expense) by line item that are included in the Statement of Consolidated Income on page 50. The items in the table below are explained on pages 31 through 36.

	Before Income Taxes		
	2017	2016	2015
	(In millions)		
Sales and other operating revenues	$(22)	$—	$—
Gains (losses) on asset sales, net	(98)	27	48
Other, net	—	—	(83)
Marketing, including purchased oil and gas	—	—	(39)
Operating costs and expenses	—	(164)	(51)
Exploration expenses, including dry holes and lease impairment	(280)	(1,029)	(518)
General and administrative expenses	(11)	(1)	(42)
Loss on debt extinguishment	—	(148)	—
Depreciation, depletion and amortization	(19)	—	(3)
Impairment	(4,203)	(67)	(1,616)
Total Items Affecting Comparability of Earnings Between Periods, Pre-Tax	$(4,633)	$(1,382)	$(2,304)

Comparison of Results

Exploration and Production

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

	2017	2016	2015
	(In millions)		
Revenues and Non-Operating Income			
Sales and other operating revenues	$5,460	$4,755	$6,627
Gains (losses) on asset sales, net	(39)	27	31
Other, net	2	16	(61)
Total revenues and non-operating income	5,423	4,798	6,597
Costs and Expenses			
Marketing, including purchased oil and gas	1,335	1,128	1,445
Operating costs and expenses	1,250	1,662	1,733
Production and severance taxes	119	101	146
Midstream tariffs	543	497	474
Exploration expenses, including dry holes and lease impairment	507	1,442	881
General and administrative expenses	225	232	313
Depreciation, depletion and amortization	2,736	3,113	3,833
Impairment	4,203	—	1,616
Total costs and expenses	10,918	8,175	10,441
Results of Operations Before Income Taxes	(5,495)	(3,377)	(3,844)
Provision (benefit) for income taxes	(1,842)	1,587	(1,117)
Net Income (Loss) Attributable to Hess Corporation	$(3,653)	$(4,964)	$(2,727)

Excluding the E&P items affecting comparability of earnings between periods in the table on page 31, the changes in E&P results are primarily attributable to changes in selling prices, production and sales volumes, marketing expenses, cash operating costs, Midstream tariffs, depreciation, depletion and amortization, exploration expenses and income taxes, as discussed below.

Selling Prices: Average worldwide realized crude oil selling prices, including hedging, were 26% higher in 2017 compared to the prior year, primarily due to the increase in Brent and WTI crude oil prices. In addition, realized worldwide selling prices for natural gas liquids increased in 2017 by 84% and worldwide natural gas prices remained unchanged, compared to the prior year. In total, higher realized selling prices improved 2017 financial results by approximately $350 million after income taxes compared with 2016. Our average selling prices were as follows:

	2017	2016	2015
Crude Oil - Per Barrel (Including Hedging)			
United States			
Onshore	$46.04	$36.92	$42.67
Offshore	47.34	37.47	46.21
Total United States	46.50	37.13	44.01
Europe	55.03	43.33	55.10
Africa	53.17	41.88	53.89
Asia	56.99	42.98	52.74
Worldwide	49.23	39.20	47.85
Crude Oil - Per Barrel (Excluding Hedging)			
United States			
Onshore	$46.76	$36.92	$41.22
Offshore	48.15	37.47	46.21
Total United States	47.25	37.13	43.11
Europe	55.14	43.33	52.37
Africa	53.25	41.88	51.57
Asia	56.99	42.98	52.74
Worldwide	49.75	39.20	46.37
Natural Gas Liquids - Per Barrel			
United States			
Onshore	$17.67	$9.18	$9.18
Offshore	21.34	13.96	14.40
Total United States	18.10	9.71	10.02
Europe	29.04	19.48	24.59
Worldwide	18.35	9.95	10.52
Natural Gas - Per Mcf			
United States			
Onshore	$1.96	$1.48	$1.64
Offshore	2.22	1.99	2.03
Total United States	2.03	1.61	1.77
Europe	4.42	3.97	6.72
Asia and other	4.27	5.31	5.97
Worldwide	3.37	3.37	4.16

During 2017, we purchased Brent crude oil price collars to hedge 20,000 barrels of oil per day (bopd) with a weighted average contract life of 10.3 months in 2017. The collars had a floor price of $55 per barrel and a ceiling price of $75 per barrel. We also purchased West Texas Intermediate (WTI) crude oil price collars to hedge 110,000 bopd with a weighted average contract life of 7.6 months in 2017 that had a floor price of $50 per barrel and an average ceiling price of $69 per barrel. At December 31, 2017, we have open WTI crude oil price collars with an average monthly floor price of $50 per barrel and an average monthly ceiling price of $65 per barrel with a notional amount of 115,000 bopd for full year 2018. See Note 23, Financial Risk Management Activities in the Notes to Consolidated Financial Statements.

Realized and unrealized movements in crude oil price collars decreased Sales and other operating revenues by $59 million ($59 million after income taxes) in 2017 and increased Sales and other operating revenues by $126 million ($79 million after income taxes) in 2015. There were no crude oil hedge contracts in 2016.

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

	2017	2016	2015
	(In thousands)		
Crude Oil - Barrels			
United States			
Bakken	67	68	81
Other Onshore	6	9	10
Total Onshore	73	77	91
Offshore	39	45	56
Total United States	112	122	147
Europe	28	33	38
Africa	35	34	51
Asia	2	2	2
Worldwide	177	191	238
Natural Gas Liquids - Barrels			
United States			
Bakken	28	27	20
Other Onshore	8	11	12
Total Onshore	36	38	32
Offshore	5	5	6
Total United States	41	43	38
Europe	1	1	1
Worldwide	42	44	39
Natural Gas - Mcf			
United States			
Bakken	62	61	64
Other Onshore	92	133	109
Total Onshore	154	194	173
Offshore	57	64	87
Total United States	211	258	260
Europe	33	43	43
Asia and other	276	222	282
Worldwide	520	523	585
Barrels of Oil Equivalent	306	322	375
Crude oil and natural gas liquids as a share of total production	72 %	73 %	74 %

In 2018, we expect net production, excluding Libya and reflecting an estimated 15,000 boepd reduction due to the extended Enchilada platform shutdown, to average between 245,000 boepd and 255,000 boepd, compared to full year pro forma 2017 net production, excluding Libya and assets sold, of 242,000 boepd.

Production variances related to 2017, 2016 and 2015 are summarized as follows:

United States: Onshore crude oil production was lower in 2017, compared to 2016, primarily due to the sale of our Permian assets in August 2017. Onshore natural gas production was lower in 2017 compared to 2016, primarily due to natural decline in the Utica shale play. Total offshore production was lower in 2017 compared to 2016, due to production from several fields being shut-in following a fire at the third-party operated Enchilada platform in November 2017 and natural field decline, partially offset by higher production from the Tubular Bells Field. Onshore crude oil production was lower in 2016, compared to 2015, primarily due to reduced drilling activity in the Bakken shale play in response to low oil prices, while the increase in natural gas liquids production was primarily due to greater processed volumes at the Tioga gas plant. Onshore natural gas production was higher in 2016, compared to 2015, primarily due to a higher number of wells being on production in the Utica shale play relative to the prior year. Total offshore production was lower in 2016, compared to 2015, primarily due to subsurface valve failures in three wells at the Tubular Bells Field, a shut-in well to replace a subsurface valve at the Conger Field, extended planned shutdowns on third-party hosted production facilities at the Tubular Bells and Conger Fields, and natural field decline. Our interests in Permian, which were sold in August, averaged net production of 4,000 boepd in 2017 (2016: 7,000 boepd; 2015: 9,000 boepd).

Europe: Crude oil and natural gas production was lower in 2017, compared to 2016, primarily due to natural field decline. Crude oil production was lower in 2016, compared to 2015, primarily due to lower drilling activity, natural field decline and a planned shutdown at the Valhall Field, offshore Norway. Our interests in Norway, which were sold in December, averaged net production of 24,000 boepd in 2017 (2016: 28,000 boepd; 2015: 33,000 boepd).

Africa: Crude oil production in 2017 was comparable to 2016, as lower volumes from Equatorial Guinea, which was sold in November 2017, was offset by higher production in Libya. Crude oil production in Africa was lower in 2016, compared to 2015, as a result of reduced drilling activity in Equatorial Guinea and the sale of our Algeria asset in the fourth quarter of 2015. Our interests in Equatorial Guinea averaged net production of 25,000 boepd in 2017 (2016: 33,000 boepd; 2015: 43,000 boepd).

Asia: Natural gas production was higher in 2017, compared to 2016, primarily due to first production at the North Malay Basin full-field development in July 2017. Natural gas production was lower in 2016, compared to 2015, primarily due to the planned shutdown of production facilities at the JDA in 2016 to commission a booster compressor project and from lower production entitlement.

Sales Volumes: The impact of lower sales volumes decreased after-tax results by approximately $190 million in 2017 compared to 2016. Worldwide sales volumes from Hess net production, excluding purchased crude oil, natural gas liquids and natural gas, were as follows:

	2017	2016	2015
	(In thousands)		
Crude oil - barrels	63,367	72,462	85,344
Natural gas liquids - barrels	15,152	16,055	14,400
Natural gas - mcf	190,089	191,482	213,195
Barrels of Oil Equivalent	110,201	120,431	135,277
Crude oil - barrels per day	173	198	234
Natural gas liquids - barrels per day	42	44	39
Natural gas - mcf per day	520	523	584
Barrels of Oil Equivalent Per Day	302	329	371

Marketing, including purchased oil and gas: This expense category is mainly comprised of costs to purchase crude oil, natural gas liquids and natural gas from our partners in Hess operated wells or other third-parties, primarily in the U.S., and associated transportation costs for U.S. marketing activities. The increase in 2017, compared to 2016 principally reflects the impact of higher benchmark crude oil prices on the cost of purchased volumes. The decrease in 2016, compared to 2015, principally reflects the decline in crude oil prices and lower volumes purchased.

Cash Operating Costs: Cash operating costs, consisting of operating costs and expenses, production and severance taxes and E&P general and administrative expenses, decreased by $401 million in 2017 compared with the prior year (2016: $197 million decrease versus 2015). The decrease in 2017, compared to 2016, is due to lower workover expenses, lease operating and employee costs, partially offset by higher production taxes in the Bakken. The decrease in 2016 compared to 2015 is due to lower production and cost reduction efforts, and lower production taxes in the Bakken. Operating costs in 2016 include higher workover costs to replace failed subsurface valves in the Gulf of Mexico.

Midstream Tariffs Expense: Tariffs expense in 2017 increased, compared to 2016, primarily due to higher shortfall fees in 2017. Tariffs expense in 2016 increased, compared to 2015, primarily due to increased oil gathering tariffs and shortfall fees in 2016, partially offset by lower gas volumes processed through the Tioga gas plant. For 2018, we estimate Midstream tariffs expense to be in the range of $625 million to $650 million.

Depreciation, Depletion and Amortization: Depreciation, depletion and amortization (DD&A) costs decreased by $377 million in 2017, compared to 2016, primarily due to lower production and an improved portfolio average DD&A rate due to the production mix. DD&A costs decreased in 2016, compared to 2015, primarily due to lower production and an improved portfolio average DD&A rate due to the production mix.

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

	Actual 2017	2016	2015	Forecast range 2018
Cash operating costs	$14.30	$15.56	$15.43	$13.00 — $14.00
Depreciation, depletion and amortization costs	24.53	26.40	28.00	18.00 — 19.00
Total Production Unit Costs	$38.83	$41.96	$43.43	$31.00 — $33.00

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

	2017	2016	2015
	(In millions)		
Exploratory dry hole costs	$268	$1,064	$410
Exploration lease and other impairment	44	145	182
Geological and geophysical expense and exploration overhead	195	233	289
	$507	$1,442	$881

Exploration expenses were lower in 2017, compared to 2016, primarily due to lower dry hole expense, leasehold impairment expense, geologic and seismic costs, and employee expenses. Exploration expenses were higher in 2016, compared to 2015, primarily due to higher dry hole expense partially offset by lower leasehold impairment expense, geologic and seismic costs, and employee expenses. See items affecting comparability of earnings between periods described below. For 2018, we estimate exploration expenses, excluding dry hole expense, to be in the range of $190 million to $210 million.

Income Taxes: The E&P income tax provision was a benefit of $1,842 million in 2017 (2016: $1,587 million expense; 2015: $1,117 million benefit). Excluding items affecting comparability between periods, the E&P income tax provision was an expense of $95 million in 2017 (2016: $948 million benefit; 2015: $731 million benefit). The provision in 2017 reflects higher production from Libya and lower deferred tax benefits on losses compared to the prior year. Commencing in 2017, we are generally not recognizing deferred tax benefit or expense in certain countries, primarily the U.S., Denmark (hydrocarbon tax only), Malaysia and Guyana, while we maintain valuation allowances against net deferred tax assets in these jurisdictions in accordance with the requirements of U.S. accounting standards. See E&P items affecting comparability of earnings below and Critical Accounting Policies and Estimates – Income Taxes on page 41.

Actual and forecast effective tax rates are as follows:

	Actual 2017	2016	2015	Forecast range 2018
Effective income tax benefit (expense) rate	34%	-47 %	29 %	N/A
Adjusted effective income tax benefit (expense) rate (a)	7 %	42 %	45 %	0% - 4%

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

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

	Before Income Taxes			After Income Taxes		
	2017	2016	2015	2017	2016	2015
	(In millions)					
Impairment	$(4,203)	$—	$(1,616)	$(2,250)	$—	$(1,566)
Dry hole, lease impairment and other exploration expenses	(280)	(1,021)	(518)	(280)	(745)	(301)
Gains (losses) on asset sales, net	(41)	27	28	(57)	17	10
Noncash charges on de-designated crude oil collars	(22)	—	—	(22)	—	—
Income tax adjustments	—	—	—	—	(2,869)	101
Offshore rig cost	—	(105)	—	—	(66)	—
Inventory write-off	—	(39)	(87)	—	(19)	(58)
Exit costs and other	—	(26)	(44)	—	(17)	(37)
	$(4,546)	$(1,164)	$(2,237)	$(2,609)	$(3,699)	$(1,851)

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

	Before Income Taxes		
	2017	2016	2015
	(In millions)		
Sales and other operating revenues	$(22)	$—	$—
Gains (losses) on asset sales, net	(41)	27	28
Other, net	—	—	(14)
Marketing, including purchased oil and gas	—	—	(39)
Operating costs and expenses	—	(162)	(51)
Exploration expenses, including dry holes and lease impairment	(280)	(1,029)	(518)
General and administrative expenses	—	—	(27)
Impairment	(4,203)	—	(1,616)
	$(4,546)	$(1,164)	$(2,237)

2017:

- Gains (losses) on asset sales, net: We recognized a pre-tax gain of $486 million ($486 million after income taxes) related to the sale of our assets in Equatorial Guinea, and a pre-tax gain of $330 million ($314 million after income taxes) related to the sale of our enhanced oil recovery assets in the Permian Basin. We also incurred a pre-tax loss of $857 million ($857 million after income taxes) on the sale of our interests in Norway. The loss included the recognition in earnings of $900 million for cumulative translation adjustments previously reflected within accumulated other comprehensive income. See Note 2, Dispositions in the Notes to Consolidated Financial Statements.
- Impairment: We recorded a noncash impairment charge related to our interests in Norway totaling $2,503 million pre-tax ($550 million after income taxes) in the third quarter prior to the sale of our interests in the fourth quarter. In addition, we recognized pre-tax impairment charges to reduce the carrying value of our interests in the Stampede Field by $1,095 million ($1,095 million after income taxes), and the Tubular Bells Field by $605 million ($605 million after income taxes) primarily as a result of a lower long-term crude oil price outlook. The Stampede Field had significant capitalized exploration and appraisal costs that were incurred on a 100% working interest basis on the Pony discovery prior to unitizing into the Stampede project. See Note 3, Impairment in the Notes to Consolidated Financial Statements.
- Dry hole, lease impairment and other exploration expenses: We recorded a pre-tax charge of $280 million ($280 million after income taxes) to fully impair the carrying value of our interest at the Hess operated offshore Deepwater Tano/Cape Three Points license, offshore Ghana (Hess 50% license interest) as a result of management's decision in the fourth quarter of 2017 to not develop the previously discovered fields. See Note 24, Subsequent Events in the Notes to Consolidated Financial Statements.
- Noncash charges on de-designated crude oil collars: We recorded a pre-tax charge of $22 million ($22 million after income taxes) related to certain crude oil collars not designated as cash flow hedges. The de-designation was a result of production downtime caused by a fire at the third-party operated Enchilada platform in the Gulf of Mexico during the fourth quarter.

2016:

- Dry hole, lease impairment and other exploration expenses: We recorded a pre-tax charge of $938 million ($693 million after income taxes) to write-off all previously capitalized wells and other project related costs for our Equus natural gas project, offshore the North West Shelf of Australia, following the decision to defer further development of the project. In addition, we recorded a pre-tax charge of $83 million ($52 million after income taxes) to write-off the previously capitalized Sicily-1 exploration well based on our decision not to pursue the project.
-

- Gains on asset sale, net: We recognized a pre-tax gain of $27 million ($17 million after income taxes) related to the sale of undeveloped onshore acreage in the U.S.
- Income taxes: We recorded a non-cash charge of $2,920 million to establish valuation allowances against net deferred tax assets as of December 31, 2016, as required under application of the accounting standards following a three-year cumulative loss. This deferred tax charge has no cash flow impact and the Corporation’s underlying tax position remains unchanged. In addition, we recorded a tax benefit of $51 million related to the resolution of certain international tax matters.

- Offshore rig cost: We recognized a pre-tax charge of $105 million ($66 million after income taxes) related to an offshore drilling rig.
- Inventory write-off: We incurred a pre-tax charge of $39 million ($19 million after income taxes) to write off surplus materials and supplies inventory.
- Exit costs and other: We recorded pre-tax exit and other costs of $26 million ($17 million after income taxes), which primarily relates to employee severance.

2015:

- Impairment: We recorded noncash goodwill impairment charges totaling $1,483 million pre-tax ($1,483 million after income taxes), representing all goodwill of our E&P segment, due to the decline in crude oil prices. In addition, we recorded a pre-tax charge of $133 million ($83 million after income taxes) associated with our legacy conventional North Dakota assets.
- Dry hole, lease impairment and other exploration expenses: We recognized a pre-tax charge of $190 million ($86 million after income taxes) to write-off an exploration well and other costs related to the Dinarta Block in the Kurdistan Region of Iraq following the decision of the Corporation and its partner to relinquish the block and exit operations in the region. In offshore Ghana, we expensed previously capitalized well costs of $182 million ($117 million after income taxes) primarily associated with natural gas discoveries due to insufficient progress on appraisal negotiations with the regulator. In offshore Australia, we expensed previously capitalized well costs of $62 million ($45 million after income taxes) associated with discovered resources that we determined would not be included in the development concept for the Equus project. In addition, we recorded pre-tax charges totaling $84 million ($53 million after income taxes) primarily to impair exploration leases in the Gulf of Mexico.
- Gains (losses) on asset sales, net: We recognized a pre-tax gain of $49 million ($31 million after income taxes) related to the sale of approximately 13,000 acres of Utica dry gas acreage. We also completed the sale of our producing assets in Algeria in December 2015 and recognized a pre-tax loss of $21 million ($21 million after income taxes).
- Income taxes: In 2015, we recorded net tax benefits totaling $101 million, comprised primarily of $154 million to recognize a deferred tax benefit from a legal entity restructuring, $50 million benefit from receiving approval for an international investment incentive and a $112 million charge to recognize a partial valuation allowance against foreign deferred tax assets.
- Inventory write-off: We incurred a pre-tax charge of $48 million ($30 million after income taxes) to write off surplus drilling materials based on future drilling plans and recognized a pre-tax charge of $39 million ($28 million after income taxes) to reduce crude oil inventories to their net realizable value.
- Exit costs and other: We recognized pre-tax charges totaling $21 million ($21 million after income taxes) associated with terminated international office space and incurred charges of $23 million ($16 million after income taxes) related to employee severance and other expenses.

Midstream

Following is a summarized income statement of our Midstream operations, which include results for a gas plant and associated CO_2 assets in the Permian Basin (through August 2017) and water handling assets in North Dakota that are wholly-owned by Hess:

	2017	2016	2015
	(In millions)		
Revenues and Non-Operating Income			
Sales and other operating revenues	$617	$569	$634
Losses on asset sales	(51)	—	—
Total revenues and non-operating income	566	569	634
Costs and Expenses			
Operating costs and expenses	195	218	296
General and administrative expenses	16	20	18
Depreciation, depletion and amortization	123	121	107
Impairment	—	67	—
Interest expense	26	19	10
Total costs and expenses	360	445	431
Results of Operations Before Income Taxes	206	124	203
Provision (benefit) for income taxes (a)	31	26	58
Net income (loss)	175	98	145
Less: Net income (loss) attributable to noncontrolling interests (b)	133	56	49
Net Income (Loss) Attributable to Hess Corporation	$42	$42	$96

(a) The provision for income taxes in the Midstream segment in 2017 is presented before consolidating its operations with other U.S. activities of the Company and prior to evaluating realizability of net U.S. deferred taxes. An offsetting impact is presented in the E&P segment.

(b) The partnership is not subject to tax and, therefore, the noncontrolling interest's share of net income is a pre-tax amount.

Sales and other operating revenues in 2017 increased, compared to 2016, primarily due to higher shortfall fees earned, and higher tariff rates and throughput volumes, partially offset by lower rail export revenue associated with third-party rail charges and the sale of our Permian assets in August 2017. Total revenues and non-operating income in 2016 decreased, compared to 2015, primarily as a result of lower rail export revenue associated with third-party rail charges, partially offset by recognition of shortfall fees earned.

Operating costs and expenses were lower in 2017, compared to 2016, primarily due to lower third-party rail charges and the sale of our Permian assets in August 2017. Operating costs and expenses were lower in 2016, compared to 2015, primarily due to a decrease in third-party rail charges. DD&A expenses were higher in 2017, compared to 2016, primarily due to newly completed gathering pipelines and related facilities that were placed in service. DD&A expenses were higher in 2016, compared to 2015, primarily due to capital expenditures on gathering assets and railcars that were placed in service.

The increase in interest expense in 2017, compared to 2016, and 2016 compared to 2015 reflects borrowings by Hess Infrastructure Partners LP.

For 2018, we estimate net income attributable to Hess Corporation from the Midstream segment to be in the range of $105 million to $115 million.

Items Affecting Comparability of Earnings Between Periods: We recognized a pre-tax loss of $57 million ($34 million after income taxes and noncontrolling interest) in 2017 related to the sale of our Midstream assets in the Permian Basin. Midstream results in 2016 included a pre-tax charge of $67 million ($21 million after income taxes and noncontrolling interest) to impair older specification rail cars.

Corporate, Interest and Other

The following table summarizes Corporate, Interest and Other expenses:

	2017	2016	2015
	(In millions)		
Corporate and other expenses (excluding items affecting comparability)	$160	$131	$219
Interest expense	385	380	376
Less: Capitalized interest	(86)	(61)	(45)
Interest expense, net	299	319	331
Corporate, Interest and Other expenses before income taxes	459	450	550
Provision (benefit) for income taxes	(26)	(163)	(217)
Net Corporate, Interest and Other expenses after income taxes	433	287	333
Items affecting comparability of earnings between periods, after-tax	30	923	44
Total Corporate, Interest and Other Expenses After Income Taxes	$463	$1,210	$377

Corporate and other expenses, excluding items affecting comparability, were higher in 2017, compared to 2016, primarily due to higher legal costs, increased pension settlement charges in 2017, and the recognition of a nonrecurring gain of $8 million in 2016. Corporate and other expenses were lower in 2016, compared to 2015, primarily due to reductions in employee costs, professional fees, and other general and administrative expenses, and the benefit of higher interest income and non-operating income. In 2018, after-tax Corporate and other expenses, excluding items affecting comparability of earnings between periods, are estimated to be in the range of $105 million to $115 million.

Interest expense was higher in 2017, compared to 2016, primarily due to slightly higher average borrowings. Capitalized interest expense was higher in 2017, compared to 2016, due to increased activity at the Hess operated Stampede development project and sanction of the Liza Field Phase 1 development project during 2017. Interest expense was higher in 2016, compared to 2015, but the increase in capitalized interest expense was greater over the same period with 2016 reflecting increased activity at the Stampede development project. In 2018 after-tax interest expense, net is estimated to be in the range of $345 million to $355 million as interest capitalization on the Stampede development will cease upon first production.

The benefit for income taxes is lower in 2017, compared to 2016, due to us generally not recognizing deferred tax benefit or expense in the U.S. while we maintain valuation allowances against net deferred tax assets in accordance with the requirements of U.S. accounting standards. This accounting treatment commenced on December 31, 2016. See items affecting comparability of earnings below and Critical Accounting Policies and Estimates – Income Taxes on page 41.

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

2017:

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

2016:

- Income tax: We recorded a non-cash charge of $829 million to establish valuation allowances against net deferred tax assets as of December 31, 2016, as required under application of the accounting standards following a three-year cumulative loss. This deferred tax charge has no cash flow impact and the Corporation's underlying tax position remains unchanged.

- Loss on debt extinguishment: We recorded a pre-tax charge of $148 million ($92 million after income taxes) related to the repurchase and redemption of notes to complete a debt refinancing. See Note 10, Debt, in the Notes to Consolidated Financial Statements.
- Exit costs and other: We recorded pre-tax exit and other costs of $3 million ($2 million after income taxes), which primarily relates to employee severance.

2015:

- HOVENSA LLC: We recorded a pre-tax charge of $76 million ($49 million after income taxes) associated with debtor-in-possession financing provided to HOVENSA LLC and the estimated liability resulting from its bankruptcy resolution.
- Other: We recorded a pre-tax gain of $20 million ($13 million after income taxes) from the sale of land and incurred exit costs of $6 million pre-tax ($4 million after income taxes).

Liquidity and Capital Resources

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

	2017	2016
	(In millions, except ratio)	
Cash and cash equivalents (a)	$4,847	$2,732
Current maturities of long-term debt	580	112
Total debt (b)	6,977	6,806
Total equity	12,354	15,591
Debt to capitalization ratio (c)	36.1 %	30.4 %

(a) Includes $356 million of cash attributable to Hess Infrastructure Partners (HIP), our 50/50 Midstream joint venture, at December 31, 2017 (2016: $2 million).
(b) Includes $980 million of debt outstanding from HIP at December 31, 2017 (2016: $733 million) that is non-recourse to Hess Corporation.
(c) Total debt as a percentage of the sum of total debt plus equity.

Cash Flows

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

	2017	2016	2015
	(In millions)		
Cash Flows From Operating Activities:			
Net cash provided by (used in) operating activities - continuing operations	$945	$795	$2,016
Net cash provided by (used in) operating activities - discontinued operations	—	—	(35)
Net cash provided by (used in) operating activities	945	795	1,981
Cash Flows From Investing Activities:			
Additions to property, plant and equipment - E&P	(1,788)	(1,974)	(3,952)
Additions to property, plant and equipment - Midstream	(149)	(277)	(369)
Proceeds from asset sales	3,296	140	50
Other, net	(1)	21	(44)
Net cash provided by (used in) investing activities - continuing operations	1,358	(2,090)	(4,315)
Net cash provided by (used in) investing activities - discontinued operations	—	—	109
Net cash provided by (used in) investing activities	1,358	(2,090)	(4,206)
Cash Flows From Financing Activities:			
Net cash provided by (used in) financing activities - continuing operations	(188)	1,311	2,497
Net cash provided by (used in) financing activities - discontinued operations	—	—	—
Net cash provided by (used in) financing activities	(188)	1,311	2,497
Net Increase (Decrease) in Cash and Cash Equivalents - Continuing Operations	2,115	16	198
Net Increase (Decrease) in Cash and Cash Equivalents - Discontinued Operations	—	—	74
Net Increase (Decrease) in Cash and Cash Equivalents	$2,115	$16	$272

Operating Activities:

In 2017, net cash provided by operating activities was $945 million (2016: $795 million; 2015: $1,981 million). In 2017, operating cash flows increased, compared to 2016, primarily due to higher benchmark crude oil prices and lower operating costs, partially offset by lower production volumes. Changes in working capital in 2017 were a use of cash of $780 million and primarily related to higher accounts receivable due to higher crude oil prices, abandonment expenditures, premiums on crude oil hedging contracts, pension contributions, contract termination payments for an offshore drilling rig, and crude oil delivered as line fill. In 2016, operating cash flows decreased, compared to 2015, primarily due to declining benchmark crude oil prices and changes in production volumes.

Investing Activities:

In 2017, Additions to property, plant and equipment were lower, compared to 2016, primarily due to lower development expenditures at North Malay Basin in the current year, partially offset by increased investments in Bakken and Guyana in 2017. The decrease in Additions to property, plant and equipment in 2016, compared to 2015, is primarily related to reduced drilling activity (Bakken, Utica, Norway, Denmark and Equatorial Guinea) and reduced development expenditures (Tubular Bells, North Malay Basin and the JDA).

In 2017, proceeds from the sale of assets of $3,296 million (2016: $140 million; 2015: $50 million) related to the divestiture of our interests in Equatorial Guinea, Norway, our enhanced oil recovery assets in the Permian Basin, and non-core acreage, onshore United States.

Financing Activities:

In 2017, Hess Midstream Partners LP received proceeds of $365.5 million from the issuance of common units in an initial public offering, of which $350 million was distributed 50/50 to Hess Corporation and GIP. Borrowings for debt with maturities in excess of 90 days were $800 million in 2017 (2016: $1,496 million; 2015: $600 million), while associated repayments of debt were $459 million (2016: $1,455 million; 2015: $67 million). Common and preferred stock dividends paid were $363 million in 2017 (2016: $350 million; 2015: $287 million) and we settled the repurchase of $110 million of common stock in 2017 (2016: $-; 2015: $142 million). Net outflows to noncontrolling interests were $243 million in 2017 (2016: $23 million net outflow; 2015: $2,296 million net inflow). In 2016, we issued 28,750,000 shares of common stock and depositary shares representing 575,000 shares of 8% Series A Mandatory Convertible Preferred Stock for total net proceeds of $1.64 billion.

Future Capital Requirements and Resources

At December 31, 2017, Hess Corporation, had $4.5 billion in cash and cash equivalents, excluding Midstream, and total liquidity, including available committed credit facilities, of approximately $8.9 billion. The Corporation has no significant near-term debt maturities.

Net production in 2018 is forecast to be in the range of 245,000 boepd to 255,000 boepd, excluding Libya, and we expect our 2018 E&P capital and exploratory expenditures will be approximately $2.1 billion. Based on current forward strip crude oil prices, we forecast a net operating cash flow deficit (including capital expenditures) in 2018. The Corporation expects to fund its 2018 net operating cash flow deficit (including capital expenditures), reduce debt by $500 million and repurchase $380 million of common stock with existing cash and cash equivalents.

On February 15, 2018, Hess Corporation redeemed $350 million principal amount of 8.125% notes due 2019 for $370 million.

The table below summarizes the capacity, usage, and available capacity of our borrowing and letter of credit facilities at December 31, 2017:

	Expiration Date	Capacity	Borrowings	Letters of Credit Issued	Total Used	Available Capacity
		(In millions)				
Revolving credit facility - Hess Corporation (a)	January 2021	$4,000	$ —	$ —	$ —	$ 4,000
Revolving credit facility - HIP (b)	November 2022	600	—	—	—	600
Revolving credit facility - Hess Midstream Partners LP (HESM) (c)	March 2021	300	—	—	—	300
Committed lines	Various (d)	445	—	29	29	416
Uncommitted lines	Various (d)	217	—	217	217	—
Total		$5,562	$ —	$ 246	$246	$ 5,316

(a) In January 2020, the capacity reduces to $3.7 billion.
(b) This credit facility may only be utilized by HIP and is non-recourse to Hess Corporation.
(c) This credit facility may only be utilized by HESM and is non-recourse to Hess Corporation.
(d) Committed and uncommitted lines have expiration dates through 2018.

On December 1, 2017, the Corporation amended its $4.0 billion syndicated revolving credit facility that expires in January 2020, by extending the facility for one year to January 2021, with a $3.7 billion commitment during the extension period. Borrowings on the facility will generally bear interest at 1.30% above the London Interbank Offered Rate (LIBOR). The interest rate will be higher if our credit rating is lowered. The facility contains a financial covenant that limits the amount of the total borrowings on the last day of each fiscal quarter to 60% of the Corporation's total capitalization, defined as total debt plus stockholders' equity. As of December 31, 2017, Hess Corporation had no outstanding borrowings under this facility and was in compliance with this financial covenant.

We had $246 million in letters of credit outstanding at December 31, 2017 (2016: $188 million), which primarily relate to our international operations. See also Note 23, Financial Risk Management Activities in the Notes to Consolidated Financial Statements.

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

In November 2017, HIP amended its senior unsecured syndicated credit facilities. At December 31, 2017, HIP has $800 million of senior secured syndicated credit facilities, consisting of a $600 million 5-year revolving credit facility and a drawn $200 million 5-year Term Loan A facility. The revolving credit facility can be used for borrowings and letters of credit to fund the joint venture's operating activities and capital expenditures. Borrowings under the 5-year Term Loan A facility will generally bear interest at LIBOR plus an applicable margin ranging from 1.55% to 2.50%, while the applicable margin for the 5-year syndicated revolving credit facility ranges from 1.275% to 2.000%. The interest rate is subject to adjustment based on HIP's leverage ratio, which is calculated as total debt to Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA). If HIP obtains an investment grade credit rating, as defined in the amended credit agreement, pricing levels will be based on the credit ratings in effect from time to time. The credit facilities contain financial covenants that generally require a leverage ratio of no more than 5.0 to 1.0 for the prior four fiscal quarters and an interest coverage ratio, which is calculated as EBITDA to cash interest expense, of no less than 2.25 to 1.0 for the prior four fiscal quarters. The amended credit agreement includes a secured leverage ratio test not to exceed 3.75 to 1.00 for so long as the facilities remain secured. HIP is in compliance with these financial covenants at December 31, 2017. Outstanding borrowings under this credit facility are non-recourse to Hess Corporation. At December 31, 2017, HIP's revolving credit facility was undrawn and borrowings under the Term Loan A facility amounted to $200 million, excluding deferred issuance costs. The credit facilities are secured by first-priority perfected liens on substantially all of HIP's and certain of its wholly-owned subsidiaries' directly owned assets, including its equity interests in certain subsidiaries, subject to customary exclusions.

Hess Midstream Partners LP (the "Partnership") has a $300 million 4-year senior secured syndicated revolving credit facility that became available for utilization at completion of its initial public offering in April 2017. The credit facility can be used for borrowings and letters of credit to fund operating activities and capital expenditures of the Partnership and expires March 2021. Borrowings on the credit facility will generally bear interest at LIBOR plus an applicable margin of 1.275%. The interest rate is subject to adjustment based on the Partnership's leverage ratio, which is calculated as total debt to EBITDA. If the Partnership obtains credit ratings, pricing levels will be based on the credit ratings in effect from time to time. The Partnership is subject to customary covenants in the credit agreement, including financial covenants that generally require a leverage ratio of no more than 4.5 to 1.0 for the prior four fiscal quarters. The credit facility is secured by first priority perfected liens on substantially all directly owned assets of the Partnership and its wholly-owned subsidiaries, including equity interests in subsidiaries, subject to certain customary exclusions. Outstanding borrowings under this credit facility are non-recourse to Hess Corporation. At December 31, 2017, this facility was undrawn.

Credit Ratings

Two of the three major credit rating agencies that rate the Corporation's debt have assigned an investment grade rating. At December 31, 2017, we have investment grade credit ratings with stable outlook from Standard and Poor's Ratings Services (BBB-) and Fitch Ratings (BBB-). Moody's Investors Service has rated our debt at Ba1 with a stable outlook.

The consequence of lower credit ratings is an increase in interest rates and facility fees on our credit facilities and the potential for additional required collateral under operating agreements. As of December 31, 2017, based on our current credit ratings, we may be required to issue additional collateral in the form of letters of credit up to approximately $135 million. If Fitch or S&P were to reduce their rating on our unsecured debt below investment grade, we estimate that we could be required to issue additional letters of credit up to approximately $240 million as of December 31, 2017.

In the fourth quarter of 2017, HIP obtained it first credit ratings from ratings agencies. At December 31, 2017, HIP's senior unsecured debt is rated BB+ by Standard and Poor's Ratings Services, Ba3 by Moody's Investors Service, and BB by Fitch Ratings.

Contractual Obligations and Contingencies

The following table shows aggregate information about certain contractual obligations at December 31, 2017:

	Payments Due by Period				
	Total	2018	2019 and 2020	2021 and 2022	Thereafter
	(In millions)				
Total Debt (excludes interest) (a)	$6,977	$580	$66	$167	$ 6,164
Operating Leases	1,310	387	506	141	276
Purchase Obligations:					
Capital expenditures	1,260	563	531	166	—
Operating expenses	412	230	121	39	22
Transportation and related contracts	1,221	210	390	374	247
Asset retirement obligations	801	48	129	39	585
Other liabilities	668	126	117	101	324

(a) We anticipate cash payments for interest of $418 million for 2018, $800 million for 2019-2020, $765 million for 2021-2022, and $4,340 million thereafter for a total of $6,323 million. These interest payments reflect our contractual obligations as of December 31, 2017 and, therefore, do not reflect any benefits that may arise from the previously announced $500 million debt reduction program.

Capital expenditures represent amounts that were contractually committed at December 31, 2017, including the portion of our planned capital expenditure program for 2018. Obligations for operating expenses include commitments for oil and gas production expenses, seismic purchases and other normal business expenses. Other liabilities reflect contractually committed obligations in the Consolidated Balance Sheet at December 31, 2017, including pension plan liabilities and estimates for uncertain income tax positions. The Corporation and certain of its subsidiaries lease drilling rigs, office space and other assets for varying periods under leases accounted for as operating leases.

Off-Balance Sheet Arrangements

At December 31, 2017, we had $31 million in letters of credit for which we are contingently liable. See also Note 21, Guarantees, Contingencies and Commitments in the Notes to Consolidated Financial Statements.

Foreign Operations

At December 31, 2017, we conducted E&P activities outside the U.S., principally in Africa (Libya), Asia (Joint Development Area of Malaysia/Thailand and Malaysia), South America (Guyana and Suriname), Denmark and Canada. Therefore, we are subject to the risks associated with foreign operations, including political risk, tax law changes, currency risk, corruption, and acts of terrorism. See Item 1A. Risk Factors for further details.

Critical Accounting Policies and Estimates

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

Accounting for Exploration and Development Costs: E&P activities are accounted for using the successful efforts method. Costs of acquiring unproved and proved oil and gas leasehold acreage, including lease bonuses, brokers' fees and other related costs are capitalized. Annual lease rentals, exploration expenses and exploratory dry hole costs are expensed as incurred. Costs of drilling and equipping productive wells, including development dry holes, and related production facilities are capitalized. In production operations, costs of injected CO_2 for tertiary recovery are expensed as incurred.

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

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

For reserves to be booked as proved they must be determined with reasonable certainty to be economically producible from known reservoirs under existing economic conditions, operating methods and government regulations. In addition, government and project operator approvals must be obtained and, depending on the amount of the project cost, senior management or the Board of Directors must commit to fund the project. We maintain our own internal reserve estimates that are calculated by technical staff that work directly with the oil and gas properties. Our technical staff updates reserve estimates throughout the year based on evaluations of new wells, performance reviews, new technical data and other studies. To provide consistency throughout the Corporation, standard reserve estimation guidelines, definitions, reporting reviews and approval practices are used. The internal reserve estimates are subject to internal technical audits and senior management review. We also engage an independent third-party consulting firm to audit approximately 80% of our total proved reserves each year.

Proved reserves are calculated using the average price during the twelve-month period ending December 31 determined as an unweighted arithmetic average of the price on the first day of each month within the year, unless prices are defined by contractual agreements, excluding escalations based on future conditions. As discussed in Item 1A. Risk Factors, crude oil prices are volatile which can have an impact on our proved reserves. If crude oil prices in 2018 are at levels below that used in determining 2017 proved reserves, we may recognize negative revisions to our December 31, 2017 proved undeveloped reserves. In addition, we may recognize negative revisions to proved developed reserves, which can vary significantly by asset due to differing operating cost structures. Conversely, price increases in 2018 above those used in determining 2017 proved reserves could result in positive revisions to proved developed and proved undeveloped reserves at December 31, 2018. It is difficult to estimate the magnitude of any potential net negative or positive change in proved reserves as of December 31, 2018, due to a number of factors that are currently unknown, including 2018 crude oil prices, any revisions based on 2018 reservoir performance, and the levels to which industry costs will change in response to movements in commodity prices. A 10% change in proved developed and proved undeveloped reserves at December 31, 2017 would result in an approximate $200 million pre-tax change in depreciation, depletion, and amortization expense for 2018. See the Supplementary Oil and Gas Data on pages 81 through 91 in the accompanying financial statements for additional information on our oil and gas reserves.

Midstream Joint Venture: On July 1, 2015, we sold a 50% interest in HIP to GIP for net cash consideration of approximately $2.6 billion. We consolidate the activities of HIP, which qualifies as a variable interest entity (VIE) under U.S. generally accepted accounting principles. We have concluded that we are the primary beneficiary of the VIE, as defined in the accounting standards, since we have the power through our 50% ownership to direct those activities that most significantly impact the economic performance of HIP, and are obligated to absorb losses or have the right to receive benefits that could potentially be significant to HIP. This conclusion was based on a qualitative analysis that considered HIP's governance structure, the commercial agreements between HIP and us, and the voting rights established between the members, which provide us the ability to control the operations of HIP.

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

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

Our impairment tests of long lived E&P producing assets are based on our best estimates of future production volumes (including recovery factors), selling prices, operating and capital costs, the timing of future production and other factors, which are updated each time an impairment test is performed. We could have impairment if the projected production volumes from oil and gas fields decrease, crude oil and natural gas selling prices decline significantly for an extended period or future estimated capital and operating costs increase significantly. As a result of the extended period of low crude oil prices, we tested our oil and gas properties for impairment. See Note 3, Impairment in the Notes to Consolidated Financial Statements.

Impairment of Goodwill: Goodwill is tested for impairment annually on October 1st or when events or circumstances indicate that the carrying amount of the goodwill may not be recoverable based on a two-step process. We conduct the goodwill test at a reporting unit level, which is defined in accounting standards as an operating segment or one level below an operating segment. The reporting unit or units used in an evaluation and measurement of goodwill for impairment testing are determined from a number of factors, including the manner in which the business is managed. At December 31, 2017, our Midstream operating segment had goodwill of $360 million that resulted from an allocation from our E&P segment upon the formation of the Midstream segment in 2015. Our E&P segment has no goodwill at December 31, 2017.

In step one of the impairment test, the fair value of a reporting unit is compared with its carrying amount, including goodwill. If the fair value of the reporting unit exceeds its carrying value, goodwill is not impaired. If the carrying value of the reporting unit exceeds its fair value, we perform step two to determine possible impairment by comparing the implied fair value of goodwill with the carrying amount. The implied fair value of goodwill is determined by assuming the reporting unit is purchased at fair value with assets and liabilities of the reporting unit being reflected at fair value in the same manner as the accounting prescribed for a business combination. The resulting excess of fair value of the reporting unit over the amounts assigned to the reporting unit's assets and liabilities represents the implied fair value of goodwill. If the implied fair value of goodwill were less than its carrying amount, an impairment loss would be recorded. Fair value for the Midstream operating segment is based on a market approach using the exchange price of Hess Midstream Partners, LP, which is a consolidated publicly traded master limited partnership that operates substantially all of our Midstream segment assets.

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

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

The accounting standards require the evaluation of all available positive and negative evidence giving weight based on the evidence's relative objectivity. In evaluating potential sources of positive evidence, we consider the reversal of taxable temporary differences, taxable income in carryback and carryforward periods, the availability of tax planning strategies, the existence of appreciated assets, estimates of future taxable income, and other factors. Estimates of future taxable income are based on assumptions of oil and gas reserves, selling prices, and other subjective operating assumptions that are consistent with internal business forecasts. In evaluating potential sources of negative evidence, we consider a cumulative loss in recent years, any history of operating losses or tax credit carryforwards expiring unused, losses expected in early future years, unsettled circumstances that, if unfavorably resolved, would adversely affect future operations and profit levels on a continuing basis in future years, and carryback or carryforward periods that are so brief that it would limit realization of tax benefits if a significant deductible temporary difference is expected to reverse in a single year. Due to a sustained low commodity price environment, we remained in a three-year cumulative consolidated loss position as of December 31, 2017. A three-year cumulative consolidated loss constitutes objective negative evidence to which the accounting standards require we assign significant weight relative to subjective evidence such as our estimates of future taxable income. We are generally not recognizing deferred tax benefit or expense in certain countries, primarily the U.S., Denmark (hydrocarbon tax only), Malaysia, and Guyana, while we maintain valuation allowances against net deferred tax assets in these jurisdictions.

As of December 31, 2017, the Consolidated Balance Sheet reflects a $5,199 million valuation allowance against the net deferred tax assets for multiple jurisdictions based on the evaluation of the accounting standards described above. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income change or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as expected future growth.

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

Retirement Plans: We have funded non-contributory defined benefit pension plans, an unfunded supplemental pension plan and an unfunded postretirement medical plan. We recognize the net change in the funded status of the projected benefit obligation for these plans in the Consolidated Balance Sheet.

The determination of the obligations and expenses related to these plans are based on several actuarial assumptions, the most significant of which relate to the discount rate for measuring the present value of future plan obligations; expected long term rates of return on plan assets; the rate of future increases in compensation levels, and participant mortality assumptions. These assumptions represent estimates made by us, some of which can be affected by external factors. For example, the discount rate used to estimate our projected benefit obligation is based on a portfolio of high quality, fixed income debt instruments with maturities that approximate the expected payment of plan obligations. The expected return on plan assets is developed from the expected future returns for each asset category, weighted by the target allocation of pension assets to that asset category. The future expected return assumptions for individual asset categories are largely based on inputs from various investment experts regarding their future return expectations for particular asset categories. Changes in these assumptions can have a material impact on the amounts reported in our financial statements.

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

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

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

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

Environment, Health and Safety

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

We recognize that climate change is a global environmental concern. We assess, monitor and take measures to reduce our carbon footprint at existing and planned operations. We are committed to complying with all Greenhouse Gas (GHG) emissions mandates and the responsible management of GHG emissions at our facilities.

We will have continuing expenditures for environmental assessment and remediation. Sites where corrective action may be necessary include onshore E&P facilities, sites from discontinued operations as to which we retained liability and, although not currently significant, “Superfund” sites where we have been named a potentially responsible party.

We accrue for environmental assessment and remediation expenses when the future costs are probable and reasonably estimable. At December 31, 2017, our reserve for estimated remediation liabilities was approximately $80 million. We expect that existing reserves for environmental liabilities will adequately cover costs to assess and remediate known sites. Our remediation spending was approximately $15 million in 2017 (2016: $10 million; 2015: $13 million). 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.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 23, Financial Risk Management Activities, in the Notes to Consolidated Financial Statements, in the normal course of our business, we are exposed to commodity risks related to changes in the prices of crude oil, natural gas liquids, and natural gas as well as changes in interest rates and foreign currency values. In the disclosures that follow, financial risk management activities refer to the mitigation of these risks through hedging activities.

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

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

- Swaps: We use financially settled swap contracts with third-parties as part of our financial risk management activities. Cash flows from swap contracts are determined based on underlying commodity prices or interest rates and are typically settled over the life of the contract.
- Forward Foreign Exchange Contracts: We enter into forward contracts, primarily for the British Pound, which commit us to buy or sell a fixed amount of British Pound at a predetermined exchange rate on a future date. In 2017, we also settled forward contracts for Danish Krone.
- Exchange Traded Contracts: We may use exchange traded contracts, including futures, on a number of different underlying energy commodities. These contracts are settled daily with the relevant exchange and may be subject to exchange position limits.
- Options: Options on various underlying energy commodities include exchange traded and third-party contracts and have various exercise periods. As a seller of options, we receive a premium at the outset and bear the risk of unfavorable changes in the price of the commodity underlying the option. As a purchaser of options, we pay a premium at the outset and have the right to participate in the favorable price movements in the underlying commodities.

Financial Risk Management Activities

We have outstanding foreign exchange contracts with a total notional amount of $52 million at December 31, 2017 that are used to reduce our exposure to fluctuating foreign exchange rates for various currencies. The change in fair value of foreign exchange contracts from a 10% strengthening of the U.S. Dollar exchange rate is estimated to be a loss of approximately $5 million at December 31, 2017.

At December 31, 2017, our outstanding long term debt of $6,977 million, including current maturities, had a fair value of $7,718 million. A 15% increase or decrease in the rate of interest would decrease or increase the fair value of debt by approximately $500 million or $560 million, respectively.

At December 31, 2017, we have outstanding West Texas Intermediate (WTI) crude oil collar contracts with a notional amount of 115,000 bopd for calendar 2018 with an average monthly floor price of $50 per barrel and an average monthly ceiling price of $65 per barrel. As of December 31, 2017, an assumed 10% increase in the forward WTI crude oil prices used in determining the fair value of our crude oil collars would reduce the fair value of these derivatives instruments by approximately $120 million, while an assumed 10% decrease in the same WTI crude oil prices would increase the fair value of these derivative instruments by approximately $70 million. See Note 23, Financial Risk Management Activities, in the Notes to Consolidated Financial Statements.

In 2017, we recorded a pre-tax charge of $22 million ($22 million after income taxes) related to certain crude oil collars not designated as cash flow hedges. The de-designation was as a result of expected production downtime caused by a fire at the third-party operated Enchilada platform in the Gulf of Mexico.

Item 8. Financial Statements and Supplementary Data

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

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