HESS CORP
Form 10-K
February 26, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

or

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number 1-1204

Hess Corporation

(Exact name of Registrant as specified in its charter)

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

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock (par value $1.00)	New York Stock Exchange
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 þ 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 þ

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 þ 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 þ 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. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	þ	Accelerated filer	¨	Non-accelerated filer	¨	Smaller reporting company	¨
		(Do not check if a smaller reporting company)					

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

The aggregate market value of voting stock held by non-affiliates of the Registrant amounted to $16,710,000,000, computed using the outstanding common shares and closing market price on June 30, 2015, the last business day of the Registrant's most recently completed second fiscal quarter.

At February 19, 2016, there were 315,240,299 shares of Common Stock outstanding.

Part III is incorporated by reference from the Proxy Statement for the 2016 annual meeting of stockholders.

HESS CORPORATION

Form 10-K

TABLE OF CONTENTS

Unless the context indicates otherwise, references to "Hess", the "Corporation", "Registrant", "we", "us", "our" and "its" refer 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,” “believe,” “intend,” “project,” “plan,” “predict,” “will, 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. Forward-looking statements are subject to certain risks and uncertainties that could cause actual results to differ materially from our historical experience and our current projections or expectations. As and when made, we believe that these forward-looking statements are reasonable. However, 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. We are not obligated 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.

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, Equatorial Guinea, the Joint Development Area of Malaysia/Thailand (JDA), Malaysia, and Norway. The Bakken Midstream operating segment, which was established in the second quarter of 2015, provides fee-based services, including crude oil and natural gas gathering, processing of natural gas and the fractionation of natural gas liquids, transportation of crude oil by rail car, terminaling and loading crude oil and natural gas liquids, and the storage and terminaling of propane, primarily in the Bakken shale play of North Dakota. In July 2015, we sold a 50% interest in Hess Infrastructure Partners LP (HIP) for net cash consideration of approximately $2.6 billion. HIP and its affiliates primarily comprise the Bakken Midstream operating segment.

In 2013, we announced several initiatives to continue our transformation from an integrated energy company into a more geographically focused pure play E&P company. These initiatives represented the culmination of a multi-year strategic transformation designed to leverage our lean manufacturing capabilities across unconventional assets, exploit our deepwater drilling and project development capabilities, and execute a smaller, more targeted exploration program. This transformation was completed in 2015.

During 2013 through 2015, the Corporation sold mature or lower margin E&P assets in Algeria, Azerbaijan, Indonesia, Russia, Thailand, the United Kingdom (UK) North Sea, and certain interests onshore in the U.S. In addition, the transformation plan included fully exiting the Corporation’s Marketing and Refining (M&R) business, including its terminal, retail, energy marketing and energy trading operations, as well as the permanent shutdown of refining operations at its Port Reading, NJ facility. HOVENSA L.L.C. (HOVENSA), a 50/50 joint venture between the Corporation’s subsidiary, Hess Oil Virgin Islands Corp. (HOVIC), and a subsidiary of Petroleos de Venezuela S.A. (PDVSA), had previously shut down its U.S. Virgin Islands refinery in 2012 and continued operating solely as an oil storage terminal through the first quarter of 2015. In September 2015, HOVENSA filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the United States District Court of the Virgin Islands. In December 2015, the Government of St. Croix ratified a new operating agreement with the buyer of HOVENSA’s storage terminals, refining units, and marine infrastructure (St. Croix Facility) and in January 2016, the buyer completed the purchase of the assets of the St. Croix Facility. Under the court approved Chapter 11 plan of liquidation (the “Liquidation Plan”), HOVENSA established a liquidating trust to distribute certain assets and sale proceeds to its creditors, established an environmental response trust to administer to HOVENSA’s remaining environmental obligations and will conduct an orderly wind-down of its remaining activities. See Item 3. Legal Proceedings.

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, excluding escalations based on future conditions. Crude oil prices used in the determination of proved reserves at December 31, 2015 were $55.10 per barrel for Brent (2014: $101.35) and $50.13 per barrel for WTI (2014: $94.42). Negative reserve revisions resulting from lower crude oil prices in 2015 reduced proved reserves at December 31, 2015 by 234 million barrels of oil equivalent (boe), and represent the primary reason for the decrease in total proved reserves year-on-year. These negative revisions represent primarily proved undeveloped reserves that were not economically producible at the stipulated lower prices.

Our total proved developed and undeveloped reserves at December 31 were as follows:

	Crude Oil, Condensate & Natural Gas Liquids (a)		Natural Gas		Total Barrels of Oil Equivalent (BOE) (b)	
	2015	2014	2015	2014	2015	2014
	(Millions of barrels)		(Millions of mcf)		(Millions of barrels)	
Developed						
United States	304	320	368	350	365	378
Europe (c)	126	123	123	96	147	139
Africa	148	163	137	144	171	187
Asia	5	3	643	329	112	58
	583	609	1,271	919	795	762
Undeveloped						
United States	116	311	137	270	139	356
Europe (c)	104	168	111	124	122	189
Africa	24	25	11	11	26	27
Asia	—	4	24	557	4	97
	244	508	283	962	291	669
Total						
United States	420	631	505	620	504	734
Europe (c)	230	291	234	220	269	328
Africa	172	188	148	155	197	214
Asia	5	7	667	886	116	155
	827	1,117	1,554	1,881	1,086	1,431

(a) Total proved reserves of natural gas liquids were 101 million barrels (proved developed - 63 million barrels; proved undeveloped – 38 million barrels) at December 31, 2015, and 145 million barrels (proved developed - 65 million barrels; proved undeveloped - 80 million barrels) at December 31, 2014. Of the total proved natural gas liquids reserves, 72% were in the U.S. and 28% were in Norway at December 31, 2015 (2014: 82% and 18%, respectively). Natural gas liquids do not sell at prices equivalent to crude oil. See the average selling prices in the table on page 8.

(b) 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 8.

(c) Proved reserves in Norway, which represented 21% of our total reserves at December 31, 2015 (2014: 20%), were as follows:

	Crude Oil, Condensate & Natural Gas Liquids		Natural Gas		Total Barrels of Oil Equivalent (BOE) (b)	
	2015	2014	2015	2014	2015	2014
	(Millions of barrels)		(Millions of mcf)		(Millions of barrels)	
Developed	98	95	84	67	112	106
Undeveloped	100	161	107	113	118	180
Total	198	256	191	180	230	286

Proved undeveloped reserves were 27% of our total proved reserves at December 31, 2015 on a boe basis (2014: 47%). Proved reserves held under production sharing contracts totaled 5% of our crude oil and natural gas liquids reserves, and 44% of our natural gas reserves at December 31, 2015 (2014: 5% and 49%, 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 83 through 91, which includes a discussion of the implications that potential sustained lower crude oil prices may have on proved reserves at December 31, 2016.

Production

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

	2015	2014	2013
Crude oil (thousands of barrels per day)			
United States			
Bakken	81	66	55
Other Onshore	10	10	10
Total Onshore	91	76	65
Offshore	56	51	43
Total United States	147	127	108
Europe			
Norway	27	25	20
Denmark	11	11	8
Russia	—	—	16
	38	36	44
Africa			
Equatorial Guinea	44	43	44
Libya	—	4	13
Algeria	7	7	5
	51	54	62
Asia			
Azerbaijan	—	—	2
Indonesia	—	—	5
Joint Development Area of Malaysia/Thailand (JDA) and Other	2	3	4
	2	3	11
Total	238	220	225

	2015	2014	2013
Natural gas liquids (thousands of barrels per day)			
United States			
Bakken	20	10	6
Other Onshore	12	7	4
Total Onshore	32	17	10
Offshore	6	6	5
Total United States	38	23	15
Europe	1	1	1
Asia	—	—	1
Total	39	24	17

	2015	2014	2013
Natural gas (thousands of mcf per day)			
United States			
Bakken	64	40	38
Other Onshore	109	47	25
Total Onshore	173	87	63
Offshore	87	78	61
Total United States	260	165	124
Europe			
Norway	28	25	15
Denmark	15	11	7
United Kingdom	—	—	1
	43	36	23
Asia and Other			
Joint Development Area of Malaysia/Thailand (JDA)	230	222	235
Thailand	—	29	87
Indonesia	—	1	52
Malaysia (a)	52	60	33
Other	—	—	11
	282	312	418
Total	585	513	565
Barrels of oil equivalent (per day) (b)	375	329	336

(a) Includes 15 mmcf, 20 mmcf, and 27 mmcf per day of production for 2015, 2014, and 2013, respectively from Block PM301 which is unitized into the JDA.

(b) Reflects natural gas production converted on the basis of relative energy content (six mcf equals one barrel of oil equivalent). 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. In addition, natural gas liquids do not sell at prices equivalent to crude oil. See the average selling prices in the table on page 8.

E&P Operations

A description of our significant E&P operations is as follows:

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, the Utica Basin of Ohio, the Permian Basin of Texas and offshore properties in the Gulf of Mexico.

Onshore:

Bakken: At December 31, 2015, we held 583,000 net acres in the Bakken. During 2015, we operated an average of 8.5 rigs, drilled 182 wells, completed 212 wells, and brought on production 219 wells, bringing the total operated production wells to 1,201. In 2016, we plan to operate an average of 2 rigs to drill approximately 50 wells and bring approximately 80 wells on production. The improved efficiency of our drilling operations can largely be attributed to application of our lean manufacturing capabilities.

Utica: We own a 50% working interest in approximately 50,000 net acres in the wet gas area of the Utica Basin of Ohio. During 2015, a total of 24 wells were drilled, 32 wells were completed and 32 wells were brought on production. In June 2015, we and our joint venture partner reduced drilling activity to a single Hess operated rig, and in 2016 we plan to suspend drilling activities after we bring onto production 14 wells. In 2015, we sold approximately 13,000 acres of Utica dry gas acreage for consideration of approximately $120 million.

Permian: We operate and hold a 34% interest in the Seminole San Andres Unit in the Permian Basin.

Offshore: At December 31, 2015, we held interests in 108 blocks in the deepwater Gulf of Mexico. Our production offshore in the Gulf of Mexico was principally from the Tubular Bells (Hess 57%), Shenzi (Hess 28%), Llano (Hess 50%), Conger (Hess 38%), Baldpate (Hess 50%), Hack Wilson (Hess 25%) and Penn State (Hess 50%) fields. In addition, we are operator of the Stampede development project (Hess 25%) and have interests in non-operated exploration blocks including Sicily (Hess 25%) and Melmar (Hess 35%). At December 31, 2015, we held 75 exploration blocks containing approximately 250,000 net undeveloped acres of which leases for 46 exploration blocks containing 165,000 net undeveloped acres are due to expire in the next three years. During 2015, our interests in 73 exploration blocks expired or were relinquished.

Descriptions of our significant operations in the Offshore, U.S. is as follows:

Tubular Bells: At this Hess operated field, we achieved our first full year of production following first oil in late 2014. Four production wells have been completed to date. In 2016, we intend to complete one water injector well, drill one production well, perform two wellbore stimulations, and complete a workover on a third well to open a stuck subsurface safety valve.

Shenzi: At this BHP Billiton Petroleum operated field, drilling continued during 2015 with the completion of two production wells and one appraisal well. In 2016, the operator plans to complete a water injection well.

Stampede: At this Hess operated project in the Green Canyon area of the Gulf of Mexico, the co-owners sanctioned the field development and committed to two deepwater drilling rigs in 2014. The first rig is expected to commence drilling in the first quarter of 2016 and the second rig is expected to commence drilling in the first quarter of 2017. Construction of production facilities and subsea equipment is underway, with first production from the field targeted for 2018 at an expected net rate of 15,000 barrels of oil equivalent per day (boepd).

Sicily: At this Chevron operated prospect in the Keathley Canyon area of the deepwater Gulf of Mexico, the operator successfully completed drilling and logging activities of its initial exploration well in 2015. The discovery well was drilled to a depth of 30,214 feet and is being evaluated. Drilling of an appraisal well to further evaluate the discovery commenced in December 2015.

Melmar: At this ConocoPhillips operated prospect in the Alaminos Canyon area of the deepwater Gulf of Mexico, the operator commenced drilling of an initial exploration well in December 2015.

Europe

Norway: At the BP operated offshore Valhall Field (Hess 64%), in 2015 the operator drilled one well and completed three wells. In the first quarter of 2013, the operator completed the installation of a new production, utilities and accommodation platform that extended the field life by approximately 40 years. In 2016, the operator is expected to continue a multi-year well abandonment program.

Denmark: At the Hess operated offshore South Arne Field (Hess 62%), we expect to complete drilling of a previously sanctioned eleven well multi-year program in the first quarter of 2016.

Africa

Equatorial Guinea: At the Hess operated offshore Block G (Hess 85% paying interest, national oil company of Equatorial Guinea 5% carried interest), we have production from the Okume and Ceiba Fields. In 2015, we deferred the remaining portion of an infill drilling program on the Okume Field.

Algeria: Prior to its sale on December 31, 2015, we had a 49% interest in a venture with the Algerian national oil company that redeveloped three onshore oil fields.

Ghana: At the Hess operated offshore Deepwater Tano/Cape Three Points license (Hess 50% license interest), we have drilled seven successful exploration wells on the block since 2011. In May 2013, we submitted appraisal plans for each of the seven discoveries, which comprise both oil and natural gas, to the Ghanaian government for approval. Five appraisal plans have been approved and discussions continue with the Ghanaian government to receive approval on the remaining two appraisal plans. In 2014, we drilled three successful appraisal wells. Well results continue to be evaluated and development planning is progressing. The government of Côte d'Ivoire has challenged the maritime border between it and the country of Ghana, which includes a portion of our Deepwater Tano/Cape Three Points license. We are unable to proceed with development of this license until there is a resolution of this matter, which may also impact our ability to develop the license. The International Tribunal for Law of the Sea is expected to render a final ruling on the maritime border dispute in 2017. Under terms of our license, the deadline to declare commerciality for the Pecan Field, which would be the primary development hub for the block, is in March 2016, and the deadline to submit a plan of development is in September 2016. We have requested an extension of the submission deadline for a plan of development for the Pecan Field, and will continue to work with the government on how best to progress work on the Block given the maritime border dispute. See Capitalized Exploratory Well Costs in Note 5, Property, Plant and Equipment in the Notes to the Consolidated Financial Statements for details of wells capitalized at December 31, 2015 and previously capitalized well costs charged to expense in 2015.

Libya: At the onshore Waha concession in Libya, which include the Defa, Faregh, Gialo, North Gialo and Belhedan Fields (Hess 8%), the operator shut in production in 2015 and for much of 2014 due to civil unrest. Net production averaged 4,000 bopd in 2014 and 13,000 bopd in 2013. Since December 2014, the national oil company of Libya has declared force majeure with respect to the Waha concession. We have after-tax net book value in our Libyan operations of approximately $120 million and total proved reserves of 159 million boe at December 31, 2015.

Asia and Other

Joint Development Area of Malaysia/Thailand (JDA): At the Carigali Hess operated offshore Block A-18 in the Gulf of Thailand (Hess 50%), the operator continued development drilling in 2015 and made progress on a booster compression project that is expected to be completed by the third quarter of 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. NMB achieved first production in October 2013 from an Early Production System. We expect net production to increase from approximately 40 million cubic feet per day in 2016 to approximately 165 million cubic feet per day following the completion of full field development in 2017.

Australia: At the WA 390 P Block (Hess 100%) in the Carnarvon Basin, offshore Western Australia (also known as Equus) covering approximately 780,000 acres, we have drilled 13 natural gas discoveries. In late 2014, we executed a non-binding letter of intent with a potential liquefaction partner and began joint front-end engineering studies in 2015. Discussions with potential long-term purchasers of liquefied natural gas were also initiated in 2015. Successful negotiation of a binding agreement with the third-party liquefaction partner is necessary before we can execute a gas sales agreement and sanction development of the project. At our adjacent WA-474-P Block (Hess 100%), which could become part of the Equus project, we plan to drill a commitment well in 2016. See Capitalized Exploratory Well Costs in Note 5, Property, Plant and Equipment in the Notes to the Consolidated Financial Statements for details of wells capitalized at December 31, 2015 and previously capitalized well costs charged to expense in 2015.

Guyana: At the Esso Exploration and Production Guyana Limited operated offshore Stabroek Block (Hess 30% participating interest), the operator announced a significant oil discovery at the Liza-1 well in the second quarter of 2015. The operator plans to drill two appraisal wells, including one sidetrack with a production test, and two exploration wells in 2016. A new 17,000 square kilometer 3D seismic shoot is near completion and the operator, along with its partners, continues to evaluate the resource potential of the block.

Kurdistan Region of Iraq: We relinquished our interests at the Hess operated Dinarta Block (80% paying interest, 64% working interest), and exited operations in the region in 2015.

Canada: In 2014 we acquired a 40% participating interest in four exploration licenses offshore Nova Scotia. We expect the operator, BP, to drill the first exploration well in 2017 and a second exploration well in 2018.

Sales Commitments

We have contracts to sell fixed quantities of our natural gas and natural gas liquids production. The natural gas contracts principally relate to producing fields in Asia. The most significant of these net commitments relates to the JDA where the minimum contract quantity of natural gas is estimated at 48 billion cubic feet per year based on current entitlements under a sales contract with the national oil companies of Malaysia and Thailand expiring in 2027. At the North Malay Basin development project, we have a commitment to deliver a minimum of 12 billion cubic feet of natural gas per year through 2033 from full field development start-up, which is expected in 2017. The Company’s estimated total volume of production subject to sales commitments is approximately 0.8 trillion cubic feet of natural gas. We also have natural gas liquids delivery commitments in the Bakken and Permian Basin of Texas through 2023 of approximately 9 million barrels per year, or approximately 97 million barrels over the life of the contracts.

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

Selling Prices and Production Costs

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

	2015	2014	2013
Average selling prices (a)			
Crude oil - per barrel (including hedging)			
United States			
Onshore	$42.67	$81.89	$90.00
Offshore	46.21	95.05	103.83
Total United States	44.01	87.21	95.50
Europe (b)	55.10	104.21	88.03
Africa	53.89	97.31	108.70
Asia	52.74	89.71	107.40
Worldwide	47.85	92.59	98.48
Crude oil - per barrel (excluding hedging)			
United States			
Onshore	$41.22	$81.89	$89.81
Offshore	46.21	92.22	103.15
Total United States	43.11	86.06	95.11
Europe (b)	52.37	99.20	87.45
Africa	51.57	93.70	108.07
Asia	52.74	89.71	107.40
Worldwide	46.37	90.20	98.01
Natural gas liquids - per barrel			
United States			
Onshore	$9.18	$28.92	$43.14
Offshore	14.40	30.40	29.18
Total United States	10.02	29.32	38.07
Europe (b)	24.59	52.66	58.31
Asia	—	—	74.94
Worldwide	10.52	30.59	40.68
Natural gas - per mcf			
United States			
Onshore	$1.64	$3.18	$3.08
Offshore	2.03	3.79	2.83
Total United States	1.77	3.47	2.96
Europe (b)	6.72	10.00	11.06
Asia and other	5.97	6.94	7.50
Worldwide	4.16	6.04	6.64
Average production (lifting) costs per barrel of oil equivalent produced (c)			
United States			
Onshore	$21.17	$27.08	$25.55
Offshore	7.03	5.06	4.98
Total United States	16.46	18.32	17.16
Europe (b)	23.73	29.14	36.02
Africa	23.31	22.39	19.26

Asia and other	8.46	10.67	12.89
Worldwide	17.23	19.14	19.28

(a) Includes inter company transfers valued at approximate market prices adjusted for certain processing and distribution fees.

(b) The average selling prices in Norway for 2015 were $54.89 per barrel for crude oil (including hedging), $52.15 per barrel for crude oil (excluding hedging), $24.59 per barrel for natural gas liquids and $8.58 per mcf for natural gas (2014: $105.35, $100.34, $52.13 and $12.22, respectively; 2013: $110.25, $109.41, $57.87 and $13.50, respectively). The average production (lifting) costs in Norway were $25.94 per barrel of oil equivalent in 2015 (2014: $33.76; 2013: $44.69).

(c) Production (lifting) costs consist of amounts incurred to operate and maintain our producing oil and gas wells, related equipment and facilities, transportation costs (including Bakken Midstream tariff expense starting in 2014, which amounted to $3.28 per barrel of oil equivalent in 2015 and $1.77 per barrel of oil equivalent in 2014) and production and severance taxes. The average production costs per barrel of oil equivalent reflect the crude oil equivalent of natural gas production converted on the basis of relative energy content (six mcf equals one barrel).

Lifting costs included in the table above do not include costs of finding and developing proved oil and gas reserves, or the costs of related general and administrative expenses, interest expense and income taxes.

Gross and Net Undeveloped Acreage

At December 31, 2015 gross and net undeveloped acreage amounted to:

	Undeveloped Acreage (a)	
	Gross	Net
	(In thousands)	
United States	716	459
Europe	9	1
Africa	6,433	3,123
Asia and other	14,883	6,974
Total (b)	22,041	10,557

(a) Includes acreage held under production sharing contracts.
(b) At December 31, 2015, licenses covering approximately 48% of our net undeveloped acreage held are scheduled to expire during the next three years pending the results of exploration activities. These scheduled expirations are largely in Australia and Africa.

Gross and Net Developed Acreage, and Productive Wells

At December 31, 2015 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	1,288	824	2,724	1,300	156	78
Europe (b)	102	59	69	44	—	—
Africa	9,629	833	779	104	—	—
Asia and other	259	129	—	—	88	44
Total	11,278	1,845	3,572	1,448	244	122

(a) Includes multiple completion wells (wells producing from different formations in the same bore hole) totaling 101 gross wells and 59 net wells.
(b) Gross and net developed acreage in Norway was approximately 57 thousand and 36 thousand, respectively. Gross and net productive oil wells in Norway were 49 and 31, respectively.

Exploratory and Development Wells

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

	Net Exploratory Wells			Net Development Wells		
	2015	2014	2013	2015	2014	2013
Productive wells						
United States	—	8	10	181	202	146
Europe	—	—	—	5	4	1
Africa	—	2	2	—	4	2
Asia and other	3	—	4	1	4	18

	3	10	16	187	214	167
Dry holes						
United States	—	1	—	—	—	—
Europe	—	—	3	—	—	—
Africa	1	—	—	—	—	—
Asia and other	5	3	1	—	—	—
	6	4	4	—	—	—
Total	9	14	20	187	214	167

Number of Wells in the Process of Being Drilled

At December 31, 2015 the number of wells in the process of drilling amounted to:

	Gross Wells	Net Wells
United States	70	29
Europe	1	1
Asia and other	4	2
Total	75	32

Bakken Midstream

We hold a 50% interest in HIP following the sale in July 2015 of a 50% interest to Global Infrastructure Partners (GIP) for net cash consideration of approximately $2.6 billion. HIP and its affiliates primarily comprise the Bakken Midstream operating segment which provides fee-based services including crude oil and natural gas gathering, processing of natural gas and the fractionation of natural gas liquids, terminaling and loading crude oil and natural gas liquids, transportation of crude oil by rail car and the storage and terminaling of propane, primarily in the Bakken shale play in the Williston Basin area of North Dakota. The Bakken Midstream operating segment 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 Bakken Midstream assets and operations, including routine and emergency maintenance and repair services under various operational and administrative services agreements. Prior to 2014, when providing natural gas processing services, our Bakken Midstream operating segment did not operate under a tariff arrangement and instead purchased unprocessed natural gas and provided processing services pursuant to percentage-of-proceeds contracts whereby it retained a portion of the sales proceeds received from both our E&P operating segment and third-party customers. Pursuant to these contracts, the Bakken Midstream operating segment also charged certain additional fees. The remaining proceeds were remitted back to suppliers.

Bakken Midstream assets include the following:

- Tioga gas plant: The Tioga gas plant is a natural gas processing plant is located in Tioga, North Dakota. The plant currently has a cryogenic processing capacity of 250 thousand mcf per day (mmcfd) and integrated fractionation capacity (including ethane) of 60,000 boepd following the completion of an expansion project in the first quarter of 2014. In 2015, we completed construction of a compressed natural gas (CNG) terminal at the Tioga gas plant that has a CNG compression capacity of 17,000 diesel equivalent gallons per day.
- Tioga rail terminal: The Tioga rail terminal is a crude oil and natural gas liquids rail loading facility located in Tioga, North Dakota, that includes a dual loop track with 21 crude oil loading arms. The terminal has a current crude oil loading capacity of up to 140,000 barrels of oil per day (bopd), and an estimated natural gas liquids loading capacity of approximately 30,000 bopd. The terminal also has three crude oil storage tanks with a combined shell storage capacity of 287,000 barrels.
- Crude oil train units: HIP owns a total of 1,215 crude oil rail cars at December 31, 2015 that operate as unit trains each consisting of 100 to 110 crude oil rail cars to provide crude oil transportation services to various delivery points in the East Coast, West Coast and Gulf Coast regions of the United States. Of these, 956 crude oil rail cars were constructed between May 2011 and March 2012 to AAR Petition 1577 (CPC-1232) safety standards and are capable of being upgraded to the most recent DOT-117 safety standards. The Bakken Midstream operating segment entered into a prepaid forward purchase and sales agreement with Hess Corporation to provide an additional 550 crude oil rail cars beginning in the third quarter of 2015, of which 259 were delivered at December 31, 2015. The rail cars under this arrangement are being constructed to DOT-117 standards with the exception of electronically controlled pneumatic brakes, which can be added at a later date prior to the regulation deadline, for minimal cost.
- Ramberg truck facility: The Ramberg truck facility is a crude oil truck unloading and pipeline receipt terminal that receives crude oil by pipeline or truck. The facility has a combined pipeline and truck receipt capability of 176,000 bopd, and a redelivery capability of 130,000 bopd through pipelines that connect to both the Tioga rail terminal and onto third-party pipelines.
- Gathering pipelines: HIP owns three major distinct gathering systems which collectively comprise over 3,000 miles of gathering pipelines and multiple compressor stations. These systems have a current gross throughput capacity of over 200 mmcfd of gas and 50,000 bopd of liquids.
- Mentor storage terminal: The Mentor storage terminal consists of a propane storage cavern and rail and truck transloading facility located on approximately 40 acres in Mentor, Minnesota, with aggregate working storage capacity of approximately 328,000 boe.

HIP owns 100% of Hess Midstream Partners LP, which was formed to own, operate, develop and acquire a diverse set of midstream assets to provide fee-based services to both Hess Corporation and third party crude oil and natural gas producers as a publicly traded master limited partnership upon the future completion of an initial public offering of limited partnership units. Hess Midstream Partners LP filed its most recent registration statement on Form S-1 in December 2015 and may complete an initial public offering of its securities in 2016. The assets to be held by Hess Midstream Partners LP at the time of its initial public offering are expected to include a 30% economic interest in Hess TGP Operations LP (owner of the Tioga gas plant), a 50% economic interest in Hess North Dakota Export Logistics Operations LP (owner of the Tioga rail terminal, Ramberg truck facility and crude oil rail cars), and a 100% interest in Hess Mentor Storage Holdings LLC (owner of the Mentor storage terminal).

Marketing and Refining - Discontinued Operations

As of December 31, 2015, our downstream activities had substantively ceased:

- 2015: We completed the sale of our former energy trading joint venture, HETCO.
- 2014: We sold our retail marketing business consisting of approximately 1,350 retail gasoline stations, most of which had convenience stores, and two joint venture investments in natural gas fueled electric generating projects in Newark and Bayonne, New Jersey.
- 2013: We sold our energy marketing and terminal network businesses; which marketed refined petroleum products, natural gas and electricity on the East Coast of the U.S., primarily to wholesale distributors, industrial and commercial users, and public utilities. We also permanently shut down the refining operations at our Port Reading, New Jersey facility, thus completing our exit from all refining operations.

Our subsidiary, HOVIC, had a 50% interest in HOVENSA (a joint venture with a subsidiary of PDVSA) which owned a refinery in St. Croix, U.S. Virgin Islands. In January 2012, HOVENSA shut down its refinery and continued operating solely as an oil storage terminal through the first quarter of 2015. In September 2015, HOVENSA filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the United States District Court of the Virgin Islands - Bankruptcy Division. In December 2015, the Government of St. Croix ratified a new operating agreement with the buyer of HOVENSA’s storage terminals, refining units, and marine infrastructure (St. Croix Facility) and in January 2016, the buyer completed the purchase of the assets of the St. Croix Facility. Under the court approved Liquidation Plan, HOVENSA established a liquidating trust to distribute certain assets and sale proceeds to its creditors, established an environmental response trust to administer to HOVENSA’s remaining environmental obligations and will conduct an orderly wind-down of its remaining activities. See Item 3. Legal Proceedings.

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 ensure 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 ensure that emergency procedures are comprehensive and can be effectively implemented.

To complement internal capabilities and to 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 $300 million of coverage is provided through an industry mutual insurance group. Above this $300 million threshold, insurance is carried which ranges in value up to $2.89 billion in total, depending on the asset coverage level, as described above. 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 (regardless of cause, including gross negligence and willful misconduct) and the Contractor is responsible for and indemnifies us for all claims attributable to pollution emanating from the Contractor's property. 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 the value of the contract or a fixed amount.

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 $13 million in 2015 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, 2015, we had 2,770 employees.

Website Access to Our Reports

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

13

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 prices of crude oil, natural gas liquids and natural gas, which are volatile and influenced by numerous factors beyond our control. The major foreign oil producing countries, including members of the Organization of Petroleum Exporting Countries (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. At December 31, 2015, spot prices for Brent crude oil and West Texas Intermediate crude oil closed at $36.61 per barrel and $37.13 per barrel, respectively. Average prices for 2015 were $53.64 per barrel for Brent and $48.80 per barrel for WTI. If crude oil prices in 2016 remain at levels consistent with or below year-end 2015, there will be a significant decrease in 2016 revenues and operating results from 2015 levels. We cannot predict how long these lower price levels will continue to prevail. 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. To the extent that we engage in hedging activities to mitigate commodity price volatility, we may not realize the benefit of price increases above the hedged price. 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. 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.

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. Persistent lower crude oil and natural gas prices, such as those currently prevailing, 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 resulting in a significant reduction to our proved reserves as of December 31, 2015. If crude oil prices remain at current levels or decline further, it could have a material adverse effect on our estimated proved reserves and 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 transport some of our crude oil production, particularly from the Bakken shale oil play, by rail. Recent rail accidents have raised public awareness of rail safety and resulted in heightened regulatory scrutiny. In the wake of these accidents, several U.S. government agencies have issued safety advisories or emergency orders requiring rail carriers to take additional precautionary measures when shipping crude oil by rail. In 2015, the Department of Transportation issued new standards for tank car design which could require HIP to retrofit or upgrade its existing fleet of tank cars. The requirements of these new regulatory actions, as well as other possible regulations or voluntary measures by the rail industry aimed at increasing rail safety, may lead to a significant increase in the costs of transporting crude oil and other hydrocarbons by rail and otherwise adversely 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 2015, we had a net loss attributable to Hess Corporation of $3,056 million, and if commodity prices remain low through 2016, we are forecasting a net loss for 2016. Two of the three major credit rating agencies that rate our debt have assigned an investment grade rating. In January 2016, Fitch Ratings (Fitch) affirmed our BBB credit rating but revised the rating outlook to negative. In February 2016, Standard and Poor's Ratings Services (S&P) lowered our investment grade credit rating one notch to BBB- with stable outlook and Moody's Investors Service (Moody's) lowered our credit rating to Ba1 with stable outlook, which is below investment grade. Although, currently we do not have any borrowings under our long-term credit facility, further ratings downgrades, 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 impacting our ability to obtain financing on satisfactory terms, or at all. 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 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 used to produce petroleum fuels, which through normal customer use may 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.

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. Many competitors, including national oil companies, are larger and have substantially greater resources. We are also in competition with producers of other forms of energy. 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, such as the third-party accident at the Macondo prospect, pipeline interruptions and ruptures, severe weather, geological events, labor disputes or cyber attacks. Although we maintain insurance coverage against 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. We are involved in several large development projects and the completion of those projects may be delayed beyond what was originally anticipated. 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 and unfavorable weather conditions. 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. The derivation and monitoring of successful strategies and related policies may be negatively impacted by the departure of key members of senior management. Moreover, an inability to recruit and retain adequate numbers of experienced technical and professional personnel in the necessary locations may prohibit us from executing our strategy in full or, in part, with a commensurate impact on shareholder value.

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 risk 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 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. In addition, 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.

Cyber attacks targeting computer, telecommunications systems, and infrastructure used by the oil and gas industry 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. Cyber attacks could compromise our computer and telecommunications systems and result in disruptions to our business operations or the 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 cyber attack against these operating systems, or 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 cyber-attack could have a material adverse impact on our cash flows and results of operations. 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. In addition, as technologies evolve and these attacks become more sophisticated, we may incur significant costs to upgrade or enhance our security measures to protect against such attacks.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

We, along with many companies 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. 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. An action brought by the Commonwealth of Puerto Rico was settled in conjunction with the Bankruptcy Court’s confirmation of HOVENSA’s Liquidation Plan, which is described below.

We received a directive from the New Jersey Department of Environmental Protection (NJDEP) to remediate contamination in the sediments of the lower Passaic River and 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. The EPA is continuing to study contamination and remedial designs for other portions of the River. To that end, in April 2014 EPA issued a Focused Feasibility Study (“FFS”) proposing to conduct bank-to-bank dredging of the lower eight miles of the Passaic River at an estimated cost of $1.7 billion. EPA may issue a Record of Decision (“ROD”) in 2016 selecting a remedy for the lower eight miles based on the FFS, but the ultimate remedy (and associated cost) for the lower Passaic River remains uncertain at this stage. The ROD is unlikely to address an additional nine miles of the Passaic River, 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 the ongoing studies and the fact that EPA has not yet selected a remedy for part or all of the lower Passaic River, remedial costs cannot be reliably estimated at this time.

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 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 neutral experts selected by the parties will determine the final shares of the Remedial Design costs to be paid by each of the participants. The parties have not yet addressed the allocation of costs associated with implementing the remedy that is currently being designed.

In May 2005, the government of the U.S. Virgin Islands filed a complaint in the District Court of the Virgin Islands against HOVENSA LLC (“HOVENSA”), a 50/50 joint venture between our subsidiary, Hess Oil Virgin Islands Corp. (“HOVIC”), and a subsidiary of Petroleos de Venezuela S.A. (PDVSA), and other companies that operated industrial facilities on the south shore of St. Croix asserting that the defendants are liable under the Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”) and territorial statutory and common law for damages to natural resources. In 2014, HOVIC, HOVENSA and the government of the U.S. Virgin Islands entered into a settlement agreement pursuant to which HOVENSA paid $3.5 million and agreed to pay the government of the U.S. Virgin Islands an additional $40 million no later than December 31, 2014. On September 15, 2015, HOVENSA filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code (the “Bankruptcy Code”) in the United States District Court of the Virgin Islands - Bankruptcy Division (the “Bankruptcy Court”) and commenced a court-supervised sale of substantially all of its assets pursuant to section 363 of the Bankruptcy Code. To fund HOVENSA's sale process and orderly wind-down, HOVENSA entered into a $40 million debtor-in-possession credit facility with HOVENSA’s owners, the terms of which were approved by the Bankruptcy Court. On December 1, 2015, the Bankruptcy Court entered an order approving the sale of HOVENSA’s terminal and refinery assets to Limetree Bay Terminals, LLC (“Limetree”). The Senate of the U.S. Virgin Islands approved the sale in December 2015, and the sale to Limetree was completed on January 4, 2016. The $40 million claim held by the U.S. Virgin Islands government against HOVENSA on account of the 2014 settlement agreement was also paid from the sale proceeds. On January 19, 2016, the Bankruptcy Court entered an order confirming HOVENSA’s Chapter 11 plan of liquidation (the “Liquidation Plan”). Under the Liquidation Plan, which became effective February 17, 2016, HOVENSA established a liquidating trust to distribute certain assets and sale proceeds to its creditors, established an environmental response trust to administer to HOVENSA’s remaining environmental obligations and will conduct an orderly wind-down of its remaining activities. The Liquidation Plan also provides for releases of any claims held by HOVENSA and its bankruptcy estate against us and HOVIC, and releases any claims held by certain third-party creditors of HOVENSA against us and HOVIC, both effective upon the effective date of the Liquidation Plan. In connection with the Liquidation Plan and HOVENSA’s asset sale, HOVIC relinquished its claims against HOVENSA on account of promissory notes issued by HOVENSA to HOVIC.

On September 13, 2015, the government of the U.S. Virgin Islands filed a complaint against us in the territorial Superior Court of the Virgin Islands, Division of St. Croix, alleging, among other things, that we violated territorial statutes and committed various torts in connection with the 50% ownership interest of our subsidiary, HOVIC, in HOVENSA. In connection with the closing of HOVENSA’s asset sale to Limetree, we, the government of the U.S. Virgin Islands, HOVIC, HOVENSA, and PDVSA entered into a mutual release agreement that resulted in the dismissal, with prejudice, of all pending litigation among those parties, including the lawsuit filed by the government of the U.S. Virgin Islands against us and various tax refund lawsuits filed by HOVIC and PDVSA against the government of the U.S. Virgin Islands. As part of this agreement, the government of the U.S. Virgin Islands also granted us, HOVIC, and HOVENSA a general release of all other existing claims, with the exception of claims related to environmental matters, which were automatically released upon the establishment of the environmental response trust in connection with the Liquidation Plan.

On December 18, 2014, the EPA initiated an Administrative Complaint against HOVENSA for alleged violations of the Clean Air Act’s risk management program requirements at the St. Croix facility. In connection with the Liquidation Plan, HOVENSA has agreed to settle the EPA’s allegations with the payment of a civil penalty of $115,000.

In February 2015, the Pension Benefit Guaranty Corporation (PBGC) issued a notice of determination to terminate the HOVENSA pension plan. In connection with the HOVENSA’s sale to Limetree and the Liquidation Plan, the Corporation assumed the HOVENSA pension plan upon the effective date of the Liquidation Plan and the PBGC withdrew its notice of determination. In 2015, we recorded a charge of $30 million, primarily representing the estimated net difference between the HOVENSA pension plan obligation and fair value of the plan assets.

On July 25, 2011, the Virgin Islands Department of Planning and Natural Resources commenced an enforcement action against HOVENSA by issuance of documents titled “Notice Of Violation, Order For Corrective Action, Notice Of Assessment of Civil Penalty, Notice Of Opportunity For Hearing” (the “NOVs”). The NOVs assert violations of Virgin Islands’ Air Pollution Control laws and regulations arising out of odor incidents on St. Croix in May 2011 and proposed total penalties of $210,000. We expect that any penalties arising from this matter will be covered by the liquidating trust established under the Liquidation Plan.

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.

We are from time to time 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 such proceedings is not expected to have a material adverse effect on our financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures

None.

PART II

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

Stock Market Information

Our common stock is traded principally on the New York Stock Exchange (ticker symbol: HES). High and low sales prices were as follows:

	2015		2014	
Quarter Ended	High	Low	High	Low
March 31	$77.63	$63.81	$83.56	$73.36
June 30	79.00	64.84	99.10	82.52
September 30	67.18	47.84	104.50	93.57
December 31	64.08	47.04	94.58	63.80

Performance Graph

Set forth below is a line graph comparing the five year shareholder return 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 the Corporation.
- Proxy Peer Group comprising 13 oil and gas peer companies, including the Corporation (as disclosed in our 2015 Proxy Statement).

Comparison of Five Year Shareholder Returns

Years Ended December 31,

Holders

At February 19, 2016, there were 4,441 stockholders (based on the number of holders of record) who owned a total of 315,240,299 shares of common stock.

Dividends

In 2015 and 2014, cash dividends on common stock totaled $1.00 per share ($0.25 per quarter). In 2013, cash dividends declared on common stock totaled $0.70 per share ($0.10 per share for the first two quarters and $0.25 per share commencing in the third quarter of 2013).

Share Repurchase Activities

Our share repurchase activities for the year ended December 31, 2015, were as follows:

2015	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	Maximum Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs (c) (In millions)
January	116,250	$ 69.65	116,250	$ 1,233
February	88,765	74.64	88,765	1,226
March	46,110	74.45	15,560	1,225
April	—	—	—	1,225
May	—	—	—	1,225
June	293,005	68.26	293,005	1,205
July	407,000	61.85	407,000	1,180
August	429,312	56.40	429,312	1,156
September	98,167	57.19	98,167	1,150
October	—	—	—	1,150
November	—	—	—	1,150
December	—	—	—	1,150
Total for 2015 (d)	1,478,609	$ 63.00	1,448,059	

(a) Repurchased in open market transactions. The average price paid per share was inclusive of transaction fees.
(b) Includes 30,550 common shares repurchased at a price of $74.58 per common share on the open market, which were subsequently granted to Directors in accordance with the Non-Employee Directors' Stock Award Plan.
(c) 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.
(d) Since initiation of the buyback program in August 2013, total shares repurchased through December 31, 2015 amounted to 64.1 million at a total cost of $5.4 billion (including transaction fees) for an average cost per share of

$83.45.

Equity Compensation Plans

Following is information related to our equity compensation plans at December 31, 2015.

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	6,911,378	(a)	$ 67.77	14,241,000	(b)
Equity compensation plans not approved by security holders (c)	—		—	—	

(a) This amount includes 6,911,378 shares of common stock issuable upon exercise of outstanding stock options. This amount excludes 820,090 performance share units (PSU) for which the number of shares of common stock to be issued may range from 0% to 200%, based on our total shareholder return (TSR) relative to the TSR of a predetermined group of peer companies over a three year performance period ending December 31 of the year prior to settlement of the grant. In addition, this amount also excludes 2,819,470 shares of common stock issued as restricted stock pursuant to our equity compensation plans.

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

(c) We have a Non-Employee Director's Stock Award Plan pursuant to which each non-employee director annually receives approximately $175,000 in value of our common stock. These awards are made from shares we have purchased in the open market.

See Note 11, Share based Compensation in the Notes to the 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:

	2015	2014	2013	2012	2011
	(In millions, except per share amounts)				
Sales and other operating revenues					
Crude oil and natural gas liquids	$5,503	$9,455	$10,455	$10,802	$9,224
Natural gas	1,052	1,247	1,394	1,394	1,362
Other operating revenues	81	35	56	49	61
Total	$6,636	$10,737	$11,905	$12,245	$10,647
Income (loss) from continuing operations	$(2,959)	$1,692	$4,036	$1,808	$1,570
Income (loss) from discontinued operations	(48)	682	1,186	255	106
Net income (loss)	$(3,007)	$2,374	$5,222	$2,063	$1,676
Less: Net income (loss) attributable to noncontrolling interests*	49	57	170	38	(27)
Net income (loss) attributable to Hess Corporation	$(3,056) (a)	$2,317 (b)	$5,052 (c)	$2,025 (d)	$1,703 (e)
Net income (loss) attributable to Hess Corporation per share:					
Basic:					
Continuing operations	$(10.61)	$5.57	$11.47	$5.29	$4.60
Discontinued operations	(0.17)	2.06	3.54	0.69	0.45
Net income (loss) per share	$(10.78)	$7.63	$15.01	$5.98	$5.05
Diluted:					
Continuing operations	$(10.61)	$5.50	$11.33	$5.26	$4.56
Discontinued operations	(0.17)	2.03	3.49	0.69	0.45
Net income (loss) per share	$(10.78)	$7.53	$14.82	$5.95	$5.01
Total assets	$34,195	$38,407	$42,515	$43,222	$38,872
Total debt	$6,630	$5,987	$5,798	$8,111	$6,057
Total equity	$20,401	$22,320	$24,784	$21,203	$18,592
Dividends per share of common stock	$1.00	$1.00	$0.70	$0.40	$0.40

* Includes noncontrolling interests associated with both continuing and discontinued operations.

(a) Includes noncash charges of $1,483 million relating to write off all goodwill associated with our E&P operating segment.

(b) 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.

(c) 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 impairments, dry hole expenses, severance and other exit costs, income tax charges, refinery shutdown costs, and other charges.

(d) Includes after tax income of $661 million relating to gains on asset sales and income from the partial liquidation of LIFO inventories, partially offset by after tax charges totaling $634 million for asset impairments, dry hole expenses, income taxes and other charges.

(e) Includes after tax charges totaling $694 million relating to the shutdown of the HOVENSA L.L.C. (HOVENSA) refinery, asset impairments and an increase in the United Kingdom supplementary tax rate, partially offset by after tax income of $413 million relating to gains on asset sales.

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

Overview

Hess Corporation 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, Equatorial Guinea, the Joint Development Area of Malaysia/Thailand (JDA), Malaysia, and Norway. The Bakken Midstream operating segment, which was established in the second quarter of 2015, provides fee-based services, including crude oil and natural gas gathering, processing of natural gas and the fractionation of natural gas liquids, transportation of crude oil by rail car, terminaling and loading crude oil and natural gas liquids, and the storage and terminaling of propane, primarily in the Bakken shale play of North Dakota.

Transformation to a Pure Play E&P Company

In 2013, we announced several initiatives to continue our transformation from an integrated energy company into a more geographically focused pure play E&P company. These initiatives represented the culmination of a multi-year strategic transformation designed to leverage our lean manufacturing capabilities across unconventional assets, exploit our deepwater drilling and project development capabilities, and execute a smaller, more targeted exploration program. This transformation was completed in 2015.

During 2013 through 2015, the Corporation sold mature or lower margin E&P assets in Algeria, Azerbaijan, Indonesia, Russia, Thailand, the United Kingdom (UK) North Sea, and certain interests onshore in the U.S. In addition, the transformation plan included fully exiting the Corporation's Marketing and Refining (M&R) business, including its terminal, retail, energy marketing and energy trading operations, as well as the permanent shutdown of refining operations at its Port Reading, NJ facility. HOVENSA L.L.C. (HOVENSA), a 50/50 joint venture between the Corporation's subsidiary, Hess Oil Virgin Islands Corp. (HOVIC), and Petroleos de Venezuela S.A. (PDVSA), had previously shut down its U.S. Virgin Islands refinery in 2012. HOVENSA filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the United States District Court of the Virgin Islands in September 2015. In January 2016, Limetree Bay Terminals, LLC (Limetree) purchased the terminal and refinery assets of the St. Croix Facility and HOVENSA will conduct an orderly wind-down of its remaining activities. See Item 3. Legal Proceedings.

Response to Low Oil Prices

In 2015, we realized an adjusted net loss of $1,113 million and incurred a net operating cash flow deficit (cash flow from operating activities less cash flows from investing activities) of $2,225 million based on average 2015 West Texas Intermediate (WTI) oil prices of $48.80 per barrel (Brent - $53.64 per barrel). In response to the decline in crude oil prices that began in late 2014, we conducted an extensive company-wide review of our cost base and engaged with our suppliers to identify opportunities to reduce costs during 2015. As a result of these cost reduction efforts, we decreased E&P capital and exploratory expenditures by $400 million to $4.0 billion, and cash operating costs by approximately $300 million versus our 2015 plan.

At December 31, 2015, we had $2.7 billion in cash and cash equivalents and total liquidity including available committed credit facilities of approximately $7.4 billion. Oil and gas production in 2016 is forecast to be in the range of 330,000 to 350,000 barrels of oil equivalent per day (boepd) compared with 375,000 boepd in 2015, and we have reduced our 2016 E&P capital and exploratory expenditure budget to approximately $2.4 billion, down 40% from 2015. Capital expenditures from our Bakken Midstream joint venture are expected to be approximately $340 million in 2016. Forward strip crude oil prices for 2016 are below average prices for 2015, and as a result, we forecast a significant net loss and a net operating cash flow deficit (including capital expenditures) in 2016. In February 2016, we issued 28,750,000 shares of common stock and depositary shares representing 575,000 shares of 8% Series A Mandatory Convertible Preferred Stock, par value $1 per share, with a liquidation preference of $1,000 per share of convertible preferred stock, for total net proceeds of approximately $1.6 billion. We expect to fund our net operating cash flow deficit (including capital expenditures) for the full year of 2016 with cash on hand. Due to the low commodity price environment, we may take other steps to improve our financial position by further reducing our planned capital program and other cash outlays, accessing other sources of liquidity by issuing debt and equity securities, and/or pursuing further asset sales. See Note 23, Subsequent Events in the Notes to the Consolidated Financial Statements.

Consolidated Results

Net loss was $3,056 million in 2015 compared with net income in the prior two years (2014: $2,317 million; 2013: $5,052 million). Excluding items affecting comparability summarized on page 28, adjusted net loss was $1,113 million in 2015 compared with adjusted net income in the prior two years (2014: $1,308 million; 2013: $1,892 million). Annual production averaged 375,000 boepd (2014: 329,000 boepd; 2013: 336,000 boepd) and is expected to average between 330,000 boepd and 350,000 boepd in 2016 excluding any contribution from Libya. Total proved reserves were 1,086 million barrels of oil equivalent (boe), 1,431 million boe, and 1,437 million boe at December 31, 2015, 2014, and 2013, respectively. Lower crude oil prices in 2015 resulted in negative revisions of 234 million boe at December 31, 2015, primarily related to proved undeveloped reserves.

Significant 2015 Activities

The following is an update of significant E&P activities for 2015:

Producing E&P assets:

- In North Dakota, net production from the Bakken oil shale play averaged 112,000 boepd (2014: 83,000 boepd), with the increase from prior-year primarily due to ongoing field development. During 2015, we operated an average of 8.5 rigs, drilled 182 wells, completed 212 wells, and brought on production 219 wells, bringing the total operated production wells to 1,201 at December 31, 2015. Drilling and completion costs per operated well averaged $5.8 million in 2015, down 21% from 2014. In 2016, we plan to operate an average of two rigs to drill approximately 50 wells and bring approximately 80 wells on production while reducing capital expenditures to $425 million, down from $1.3 billion in 2015. Bakken production is forecast to average between 95,000 boepd and 105,000 boepd in 2016.
- At the Valhall Field in Norway, net production averaged 33,000 boepd (2014: 31,000 boepd), with the increase from prior-year primarily due to less facility downtime and new wells in the current period. During 2015, the operator, BP, drilled one well and completed three wells, and continued to execute a multi-year well abandonment program. Production from the Valhall Field is forecast to average approximately 30,000 boepd in 2016, with the decrease from 2015 reflecting reduced drilling activity.
- At Block A 18 of the Joint Development Area of Malaysia/Thailand (JDA), the operator, Carigali Hess Operating Company, continued drilling production wells and progressed its booster compression project that is expected to be completed by the third quarter of 2016. Production averaged 42,000 boepd (2014: 42,000 boepd), including contribution from unitized acreage in Malaysia. Production from the JDA is forecast to average approximately 35,000 boepd in 2016 due to lower entitlement and downtime associated with the booster compression project.
- At the Hess operated Tubular Bells Field, we achieved our first full year of production following first oil in late 2014. In the second half of 2015 a subsurface safety valve stuck in the closed position at one well and two other wells experienced wellbore skin effects that reduced production rates. As a result, full-year 2015 production from Tubular Bells was restricted to 19,000 boepd and we estimate full-year 2016 net production to be approximately 20,000 boepd to 25,000 boepd. In 2016, we intend to complete one water injector well, drill one production well, perform two wellbore stimulations, and complete a workover on a third well to open the stuck subsurface safety valve.
- In the North Malay Basin (NMB), in 2015 net production from the Early Production System averaged approximately 40 million cubic feet per day (2014: 43 million cubic feet per day). In 2015, we also progressed fabrication and installation of the Central Processing Platform and commenced development drilling activities associated with the full-field development project. This project is on schedule to be completed in 2017, from which production is forecast to average approximately 165 million cubic feet per day.
- At the South Arne Field, offshore Denmark, we continued drilling operations in 2015 and expect to complete drilling of a previously sanctioned eleven well multi-year program in the first quarter of 2016. Net production is forecast to average approximately between 10,000 boepd and 15,000 boepd in 2016 compared with 13,000 boepd in 2015.
- In the Utica shale, 24 wells were drilled, 32 wells were completed and 32 wells were brought into production in 2015. Net production increased to approximately 24,000 boepd in 2015. In the third quarter of 2015, we completed the sale of approximately 13,000 acres of Utica dry gas acreage for consideration of approximately $120 million. In

2016, we and our joint venture partner plan to suspend drilling activities, but will bring into production 14 wells. Net production is expected to average between 20,000 boepd and 25,000 boepd in 2016.

- In Equatorial Guinea, we deferred the remaining portion of an infill drilling program at the Okume Field to reduce spend and allow time to evaluate recently acquired 4D seismic. Net production in 2016 is expected to average between 30,000 boepd and 35,000 boepd compared with net production in 2015 of 43,000 boepd.
- In Algeria, production averaged 10,000 boepd for the fourth quarter of 2015. We sold our interests in the country on December 31, 2015.

- In Libya, civil and political unrest has largely interrupted production and crude oil export capability since August 2013. At the Waha fields (Hess 8%), the operator shut-in production for 2015 and force majeure declared by the national oil company of Libya remains in effect.

Other E&P assets:

- At the Stampede development project in the Gulf of Mexico, we expect to commence drilling of our first production well in the first quarter of 2016. Construction of production facilities and subsea equipment is underway with first production from the field targeted in 2018 at an expected net rate of 15,000 boepd.
- In Ghana, we, along with our co-owners, continued development planning and subsurface evaluation in 2015. The government of Côte d'Ivoire has challenged the maritime border between it and the country of Ghana, which includes a portion of our Deepwater Tano/Cape Three Points license. We are unable to proceed with development of this license until there is a resolution of this matter, which may also impact our ability to develop the license. The International Tribunal for Law of the Sea is expected to render a final ruling on the maritime border dispute in 2017. Under terms of our license, the deadline to declare commerciality for the Pecan Field, which would be the primary development hub for the block, is in March 2016, and the deadline to submit a plan of development is in September 2016. We have requested an extension of the submission deadline for a plan of development for the Pecan Field, and will continue to work with the government on how best to progress work on the Block given the maritime border dispute. In 2015, we expensed previously capitalized gas wells that have not sufficiently progressed appraisal negotiations with the regulator. See Capitalized Exploratory Well Costs in Note 5, Property, Plant and Equipment in the Notes to the Consolidated Financial Statements.
- At the Equus project on Block WA-390-P in the offshore Carnarvon Basin of Australia, in 2015 we initiated joint front-end engineering studies with a potential third-party liquefaction partner following the execution of a non-binding letter of intent with the same third-party liquefaction partner in 2014. In 2015, we commenced discussions with potential long-term purchasers of liquefied natural gas, and in 2016 we plan to drill a commitment well on Block WA-474-P which is adjacent to Block WA-390-P. We also wrote-off three previously capitalized wells that we determined will not be included in the current development concept. See Capitalized Exploratory Well Costs in Note 5, Property, Plant and Equipment in the Notes to the Consolidated Financial Statements.
- In Guyana at the Stabroek Block (Hess 30%), the operator, Esso Exploration and Production Guyana Limited, announced a significant oil discovery at the Liza-1 well in the second quarter of 2015. The operator plans to drill two appraisal wells, including one sidetrack with a production test, and two exploration wells in 2016. A new 17,000 square kilometer 3D seismic shoot is near completion and the operator, along with its partners, continues to evaluate the resource potential of the block.
- At the Sicily prospect (Hess 25%), in the Keathley Canyon area of the deepwater Gulf of Mexico, the operator successfully completed drilling and logging activities in 2015 of its initial exploration well. The discovery well was drilled to a depth of 30,214 feet and is being evaluated. Drilling of an appraisal well to further evaluate the discovery commenced in December 2015.
- At the Melmar prospect in the Alaminos Canyon area of the deepwater Gulf of Mexico (Hess 35%), which we entered into during 2015, the operator, ConocoPhillips, commenced exploration drilling in December 2015.
- In the Kurdistan region of Iraq (Hess 64%), we and our partner agreed to relinquish the Dinarta Block, and to exit operations in the region based on well results in 2015.

The following is an update of significant Bakken Midstream activities during 2015:

- We completed the sale of a 50% interest in our Bakken Midstream business to Global Infrastructure Partners (GIP) for cash consideration of approximately $2.6 billion and formed a joint venture with GIP. The joint venture has filed a Form S-1 with the Securities and Exchange Commission in preparation for an initial public offering of Hess Midstream Partners LP limited partnership units to the public. The joint venture expects to initiate the offering when market conditions for the sale of limited partnership units become more favorable.
- We commenced the construction of facilities and the reconfiguration of pipelines in McKenzie and Williams counties that are expected to increase throughput capacity for crude oil and natural gas originating from south of the

Missouri River for transporting north to our natural gas processing and crude oil and natural gas liquids logistics assets in Tioga and Ramberg. We currently expect these projects to be fully in service in 2017.

Liquidity, and Capital and Exploratory Expenditures

Net cash provided by operating activities was $1,981 million in 2015 (2014: $4,457 million; 2013: $5,098 million). At December 31, 2015, cash and cash equivalents were $2,716 million (2014: $2,444 million) and total debt was $6,630 million (2014: $5,987 million). Our debt to capitalization ratio, excluding the Bakken Midstream operating segment, at December 31, 2015 was 24.4%. Our debt to capitalization ratio was 21.2% at December 31, 2014. Capital and exploratory expenditures from continuing operations were as follows:

	2015	2014	2013
E&P Capital and Exploratory Expenditures			
United States			
Bakken	$1,308	$1,854	$1,632
Other Onshore	332	725	830
Total Onshore	1,640	2,579	2,462
Offshore	923	765	865
Total United States	2,563	3,344	3,327
Europe	298	540	724
Africa	161	435	630
Asia and other	1,020	986	993
E&P - Capital and Exploratory Expenditures (a)	$4,042	$5,305	$5,674

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

	2015	2014	2013
United States	$132	$125	$192
International	157	207	250
Total exploration expenses charged to income included above	$289	$332	$442

(a) The above table excludes capital expenditures of $431 million and $106 million in 2014 and 2013, respectively, related to our discontinued operations, and includes corporate capital expenditures of $53 million and $58 million in 2014 and 2013, respectively.

	2015	2014	2013
Bakken Midstream Capital Expenditures			
Bakken Midstream capital expenditures	$296	$301	$535

We anticipate investing approximately $2.4 billion on E&P capital and exploratory expenditures in 2016 reflecting a planned reduction in our work program in response to the lower commodity price environment. Bakken Midstream capital expenditures are expected to be approximately $340 million in 2016.

Consolidated Results of Operations

As described in Note 20, Segment Information, we established the Bakken Midstream operating segment in 2015 and have presented prior period numbers on a comparable basis. The after-tax income (loss) by major operating activity is summarized below:

	2015	2014	2013
	(In millions, except per share amounts)		
Net income (loss) attributable to Hess Corporation:			
Exploration and Production	$(2,717)	$2,086	$4,439
Bakken Midstream	86	10	(136)
Corporate, Interest and Other	(377)	(404)	(443)
Income (loss) from continuing operations	(3,008)	1,692	3,860
Discontinued operations	(48)	625	1,192
Total	$(3,056)	$2,317	$5,052
Net income (loss) attributable to Hess Corporation per share - Diluted:			
Continuing operations	$(10.61)	$5.50	$11.33
Discontinued operations	(0.17)	2.03	3.49
Net income (loss) attributable to Hess Corporation per share - Diluted	$(10.78)	$7.53	$14.82

The following table summarizes, on an after-tax basis, items of income (expense) that are included in net income (loss) and affect comparability between periods. The items in the table below are explained on pages 33 through 37.

	2015	2014	2013
	(In millions)		
Exploration and Production	$(1,851)	$542	$2,111
Bakken Midstream	—	—	—
Corporate, Interest and Other	(44)	(74)	(26)
Discontinued operations	(48)	541	1,075
Total items affecting comparability of earnings between periods	$(1,943)	$1,009	$3,160

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.

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

	2015	2014	2013
	(In millions)		
Net income (loss) attributable to Hess Corporation	$(3,056)	$2,317	$5,052
Less: Total items affecting comparability of earnings between periods	(1,943)	1,009	3,160
Adjusted net income (loss) attributable to Hess Corporation	$(1,113)	$1,308	$1,892

“Adjusted net income (loss)” 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).

Comparison of Results

Exploration and Production

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

	2015	2014	2013
	(In millions)		
Revenues and Non-operating Income			
Sales and other operating revenues	$6,636	$10,737	$11,887
Gains on asset sales, net	31	817	2,171
Other, net	(61)	(46)	(57)
Total revenues and non-operating income	6,606	11,508	14,001
Costs and Expenses			
Cost of products sold (excluding items shown separately below)	1,409	1,826	1,786
Operating costs and expenses	1,764	1,815	1,996
Production and severance taxes	146	275	372
Bakken Midstream tariffs	449	212	—
Exploration expenses, including dry holes and lease impairment	881	840	1,031
General and administrative expenses	317	325	362
Depreciation, depletion and amortization	3,852	3,140	2,638
Impairment	1,616	—	289
Total costs and expenses	10,434	8,433	8,474
Results of operations before income taxes	(3,828)	3,075	5,527
Provision (benefit) for income taxes	(1,111)	989	912
Net income (loss)	(2,717)	2,086	4,615
Less: Net income (loss) attributable to noncontrolling interests	—	—	176
Net income (loss) attributable to Hess Corporation	$(2,717)	$2,086	$4,439

Excluding the E&P items affecting comparability of earnings between periods in the table on page 33, the changes in E&P earnings are primarily attributable to changes in selling prices, production and sales volumes, cost of products sold, cash operating costs, depreciation, depletion and amortization, Bakken Midstream tariffs, exploration expenses and income taxes, as discussed below.

Selling Prices: Average realized crude oil selling prices, including hedging, were 48% lower in 2015 compared to the prior year, primarily due to the declines in Brent and WTI crude oil prices that commenced in the fourth quarter of 2014. In addition, realized selling prices for natural gas liquids and natural gas declined by 66% and 31%, respectively, in 2015 compared to the prior year. In total, lower realized selling prices reduced 2015 financial results by approximately $2.5 billion after income taxes compared with 2014. Our average selling prices were as follows:

	2015	2014	2013
Crude oil - per barrel (including hedging)			
United States			
Onshore	$42.67	$81.89	$90.00
Offshore	46.21	95.05	103.83
Total United States	44.01	87.21	95.50
Europe	55.10	104.21	88.03
Africa	53.89	97.31	108.70
Asia	52.74	89.71	107.40
Worldwide	47.85	92.59	98.48
Crude oil - per barrel (excluding hedging)			
United States			
Onshore	$41.22	$81.89	$89.81
Offshore	46.21	92.22	103.15
Total United States	43.11	86.06	95.11
Europe	52.37	99.20	87.45
Africa	51.57	93.70	108.07
Asia	52.74	89.71	107.40
Worldwide	46.37	90.20	98.01
Natural gas liquids - per barrel			
United States			
Onshore	$9.18	$28.92	$43.14
Offshore	14.40	30.40	29.18
Total United States	10.02	29.32	38.07
Europe	24.59	52.66	58.31
Asia	—	—	74.94
Worldwide	10.52	30.59	40.68
Natural gas - per mcf			
United States			
Onshore	$1.64	$3.18	$3.08
Offshore	2.03	3.79	2.83
Total United States	1.77		