# UNITED STATES SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# Form 10-K

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

**For the fiscal year ended December 31, 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 ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☑

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

Indicate by check mark whether the registrant submitted electronically and posted on its Corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ☑ 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 ☑

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.

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

## CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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," "target" and similar expressions identify forward-looking statements, which generally are not historical in nature. Forward-looking statements related to our operations are based on our current understanding, assessments, estimates and projections. 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.

**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:

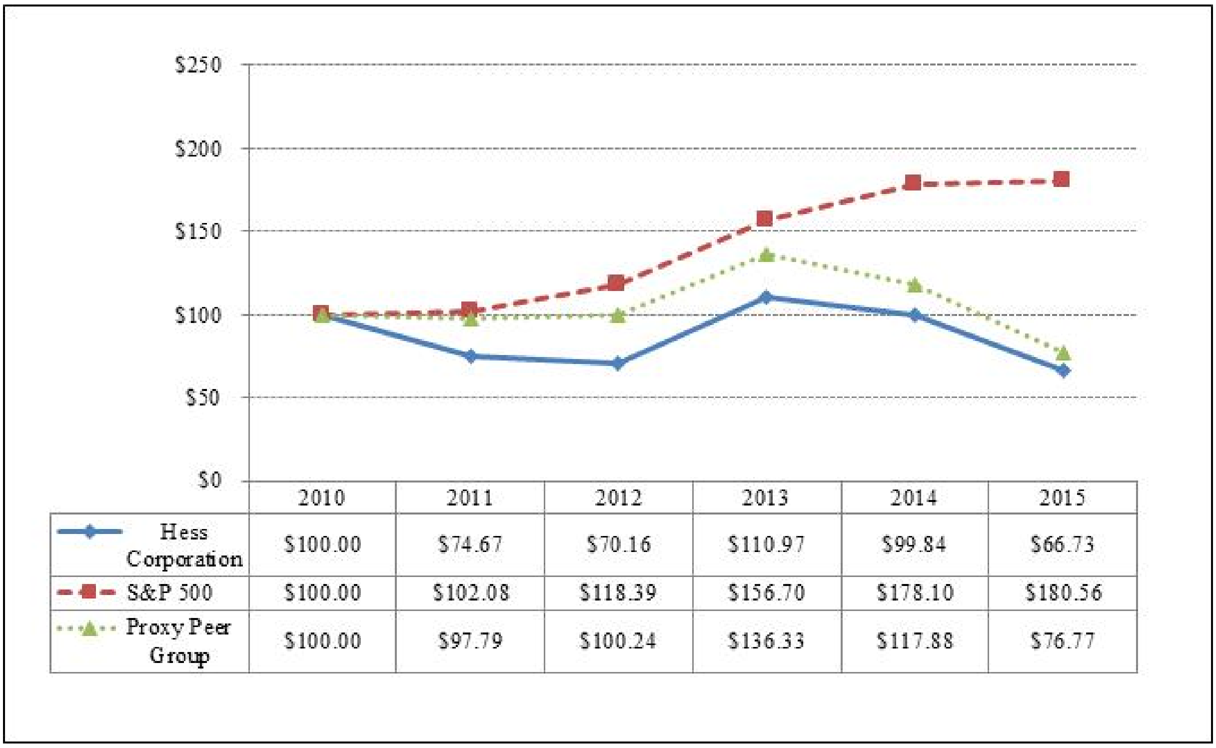
| | 2015 | | 2014 | |
|---|---|---|---|---|
| Quarter Ended | High | Low | High | Low |
| March 31 | **$ 77.63** | **$ 63.81** | $ 83.56 | $ 73.36 |
| June 30 | **79.00** | **64.84** | 99.10 | 82.52 |
| September 30 | **67.18** | **47.84** | 104.50 | 93.57 |
| December 31 | **64.08** | **47.04** | 94.58 | 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** | 3.47 | 2.96 |
| | | | |
| Europe | **6.72** | 10.00 | 11.06 |
| Asia and other | **5.97** | 6.94 | 7.50 |
| Worldwide | **4.16** | 6.04 | 6.64 |

Crude oil price hedging contracts increased E&P Sales and other operating revenues by $126 million ($79 million after income taxes) in 2015, $193 million ($121 million after income taxes) in 2014 and $39 million ($25 million after income taxes) in 2013. No crude oil hedging contracts were open at December 31, 2015.

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

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In thousands) | |
| Operating Data | | | |
| Net Production Per Day | | | |
| Crude oil - barrels | | | |
| 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 | **38** | 36 | 44 |
| Africa | **51** | 54 | 62 |
| Asia | **2** | 3 | 11 |
| Worldwide | **238** | 220 | 225 |
| Natural gas liquids - barrels | | | |
| 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 |
| Worldwide | **39** | 24 | 17 |
| Natural gas - mcf | | | |
| 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 | **43** | 36 | 23 |
| Asia and other | **282** | 312 | 418 |
| Worldwide | **585** | 513 | 565 |
| Barrels of oil equivalent (a) | **375** | 329 | 336 |
| Crude oil and natural gas liquids as a share of total production | **74%** | 74% | 72% |

(a) *Reflects natural gas production converted on the basis of relative energy content (six mcf equals one barrel). 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 on page 30.*

We expect total net production to average between 330,000 boepd and 350,000 boepd in 2016, excluding any contribution from Libya. Production variances related to 2015, 2014 and 2013 can be summarized as follows:

***United States:*** Onshore crude oil and natural gas liquids production was higher in 2015 compared to 2014, primarily due to continued drilling in the Bakken oil shale play, while the increase in natural gas production was primarily attributable to the Bakken and the Utica shale. Offshore production increased in 2015 relative to 2014 as higher production from the Tubular Bells Field, which came online in November 2014, was offset primarily by lower production from the Llano, Conger and Shenzi Fields. Crude oil, natural gas liquids and natural gas production was higher in 2014 compared with 2013, a result of continued development of the Bakken oil shale play, higher production resulting from drilling in the Utica shale and a new production well combined with lower downtime at the Llano Field in the Gulf of Mexico.

***Europe:*** Crude oil and natural gas production was higher in 2015 compared to 2014, primarily due to less facility downtime and new wells at the Valhall Field in the current year. Crude oil production was lower in 2014 compared to 2013, primarily due to the April 2013 sale of our Russian subsidiary, partially offset by higher production during 2014 at the

Valhall Field in Norway following completion of the redevelopment project in 2013. Higher natural gas production in 2014 compared to 2013 was a result of higher uptime from the Valhall Field.

***Africa:*** Crude oil production in Africa was lower in 2015 compared to 2014, due to Libyan production being shut-in. Crude oil production in Africa was lower in 2014 compared to 2013, primarily due to the shutdown of the Es Sider terminal in Libya in the third quarter of 2013, following civil unrest in the country. Net production averaged 4,000 barrels of oil per day (bopd) in 2014 and 13,000 bopd in 2013. In December 2014 the national oil company of Libya declared force majeure with respect to the Waha concession and production is currently shut-in.

***Asia and Other:*** Natural gas production was lower in 2015 compared to 2014 primarily due to asset sales partially offset by higher production at the Joint Development Area of Malaysia/Thailand (JDA) as a result of higher facility uptime. Crude oil production was lower in 2014 compared to 2013, as a result of the divestiture of our interests in the Pangkah Field in Indonesia in January 2014 and our interest in the Azeri-Chirag-Guneshli (ACG) fields, Azerbaijan in March 2013. Natural gas production was lower in 2014 compared to 2013 following the divestiture of our remaining interests in Indonesia and Thailand in 2014 and lower production from the JDA, which was partially offset by a full year of production from the North Malay Basin.

***Sales Volumes:*** Our worldwide sales volumes were as follows:

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In thousands) | |
| Crude oil - barrels | **85,344** | 80,869 | 82,402 |
| Natural gas liquids - barrels | **14,400** | 8,793 | 6,244 |
| Natural gas - mcf | **213,195** | 187,381 | 206,122 |
| Barrels of oil equivalent (a) | **135,277** | 120,892 | 123,000 |
| | | | |
| Crude oil - barrels per day | **234** | 222 | 226 |
| Natural gas liquids - barrels per day | **39** | 24 | 17 |
| Natural gas - mcf per day | **584** | 513 | 565 |
| Barrels of oil equivalent per day (a) | **371** | 331 | 337 |

(a) *Reflects natural gas production converted on the basis of relative energy content (six mcf equals one barrel). 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 on page 30.*

***Cost of Products Sold:*** Cost of products sold is mainly comprised of costs relating to the purchases of crude oil, natural gas liquids and natural gas from our partners in Hess operated wells or other third-parties, as well as rail transportation fees from our Bakken Midstream operating segment starting in 2014. The decrease in Cost of products sold in 2015 compared to 2014 principally reflects the decline in crude oil prices. Cost of products sold in 2014 was comparable to 2013 as a result of increased volumes purchased from partners in our operated wells being offset by lower purchases from third-parties.

***Cash Operating Costs:*** Cash operating costs, consisting of Operating costs and expenses, Production and severance taxes and E&P General and administrative expenses, decreased by $188 million in 2015 compared with the prior year (2014: $315 million decrease versus 2013). The decrease in 2015 compared to 2014 is due to cost reductions across the portfolio and lower production taxes in the Bakken, which were partially offset by higher operating costs at Tubular Bells where production commenced in the fourth quarter of 2014. The decrease in 2014 compared to 2013 primarily reflects lower production taxes and operating costs following the divestitures of our remaining Indonesia and Thailand assets in early 2014 and our interests in Russia in April 2013, as well as lower employee costs.

***Bakken Midstream Tariffs:*** Tariffs for 2015 primarily reflect higher volumes processed through the Tioga gas plant which was shut down during the first quarter of 2014 to complete a plant expansion and refurbishment project. The tariff arrangements were not in place prior to 2014.

***Depreciation, Depletion and Amortization:*** Depreciation, depletion and amortization (DD&A) costs increased by $712 million in 2015 from 2014 primarily reflecting higher production volumes from the Bakken, Tubular Bells and Utica fields, which had higher DD&A rates per barrel than the portfolio average. Higher production in 2014 from these fields, as well as the Valhall Field and North Malay Basin, were the primarily drivers for the increase in DD&A costs in 2014 compared to 2013.

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

| | Actual | | | Forecast |
|---|---|---|---|---|
| | 2015 | 2014 | 2013 | 2016 (a) |
| Cash operating costs | $ **15.69** | $ 20.01 | $ 21.52 | $14.50 — $15.50 |
| Depreciation, depletion and amortization costs | **28.14** | 26.10 | 21.35 | 28.50 — 29.50 |
| **Total production unit costs** | **$ 43.83** | $ 46.11 | $ 42.87 | $ 43.00 — $45.00 |
| **Bakken Midstream tariffs expense (b)** | **$ 3.28** | $ 1.77 | $ — | $3.55 — $3.95 |

*(a) Forecasted amounts assume no contribution from Libya.*

*(b) Bakken Midstream tariff arrangements were not in place prior to 2014. In 2013, Bakken Midstream earned revenues at the Tioga gas plant by purchasing unprocessed natural gas from our E&P business and third-parties, processing those hydrocarbons and selling them back to our E&P business or third-party customers based on a percentage of proceeds.*

***Exploration Expenses:*** Exploration expenses, excluding items affecting comparability of earnings described below, were lower in 2015 compared to 2014 and 2014 compared to 2013, primarily due to lower leasehold impairment expense, geologic and seismic costs, and employee expenses. For 2016, we estimate exploration expenses, excluding dry hole expense, to be in the range of $260 million to $280 million.

***Income Taxes:*** Excluding the impact of items affecting comparability of earnings between periods provided below, the effective income tax rates for E&P operations amounted to a benefit of 46% in 2015 (2014: 41% charge; 2013: 42% charge). The tax benefit in 2015 resulted from operating losses, while the increased effective rate from 2014 is due to a greater proportion of results attributable to higher tax jurisdictions. The decline in the effective tax rate from 2014 compared with 2013 was primarily due to the impact of shut-in production in Libya from the third quarter of 2013. Based on current strip crude oil prices, we are forecasting a pre-tax loss for 2016 and, as a result, the E&P effective tax rate, excluding items affecting comparability, is expected to be a benefit in the range of 41% to 45% excluding Libyan operations.

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

| | Before Income Taxes | | | After Income Taxes | | |
|---|---|---|---|---|---|---|
| | 2015 | 2014 | 2013 | 2015 | 2014 | 2013 |
| | (In millions) | | | | | |
| Impairment | **$ (1,616)** | $ — | $ (289) | **$ (1,566)** | $ — | $ (187) |
| Dry hole, lease impairment and other exploration expenses | **(518)** | (304) | (298) | **(301)** | (173) | (186) |
| Exit costs and other | **(44)** | (28) | (129) | **(37)** | (11) | (117) |
| Inventory write-off | **(87)** | — | — | **(58)** | — | — |
| Gain on asset sales, net | **28** | 801 | 2,195 | **10** | 774 | 2,145 |
| Noncontrolling interest share of gain on asset sale | **—** | — | (168) | **—** | — | (168) |
| Income taxes | **—** | — | — | **101** | (48) | 624 |
| | **$ (2,237)** | $ 469 | $ 1,311 | **$ (1,851)** | $ 542 | $ 2,111 |

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

| | Before Income Taxes | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (In millions) | | |
| Gains on asset sales, net | **$ 28** | $ 801 | $ 2,195 |
| Other, net | **(14)** | — | (8) |
| Cost of products sold (excluding items shown separately below) | **(39)** | (18) | — |
| Operating costs and expenses | **(51)** | — | (22) |
| Exploration expenses, including dry holes and lease impairment | **(518)** | (304) | (317) |
| General and administrative expenses | **(27)** | (10) | (64) |
| Depreciation, depletion and amortization | **—** | — | (16) |
| Impairment | **(1,616)** | — | (289) |
| Net income attributable to noncontrolling interest | **—** | — | (168) |
| | **$ (2,237)** | $ 469 | $ 1,311 |

Items Affecting Comparability of Earnings Between Periods were as follows:

*2015:*

- *Impairment:* We recorded noncash goodwill impairment charges totaling $1,483 million pre-tax ($1,483 million after income taxes), representing all goodwill of our E&P segment, due to the decline in crude oil prices. See *Note 6, Goodwill* in the *Notes to the Consolidated Financial Statements* for further information. In addition, we recorded a pre-tax charge of $133 million ($83 million after income taxes) associated with our legacy conventional North Dakota assets.
- *Dry hole, lease impairment and other exploration expenses:* We recognized a pre-tax charge of $190 million ($86 million after income taxes) to write-off an exploration well, associated leasehold expenses and other costs related to the Dinarta Block in the Kurdistan Region of Iraq following the decision of the Corporation and its partner to relinquish the block and exit operations in the region. In offshore Ghana, we expensed previously capitalized well costs of $182 million ($117 million after income taxes) primarily associated with natural gas discoveries that have not sufficiently progressed appraisal negotiations with the regulator. In offshore Australia, we expensed previously capitalized well costs of $62 million ($45 million after income taxes) associated with discovered resources that we determined will not be included in the current development concept for the Equus project. In addition, we recorded pre-tax charges totaling $84 million ($53 million after income taxes) primarily to impair exploration leases in the Gulf of Mexico.
- *Exit costs and other:* We recognized pre-tax charges totaling $21 million ($21 million after income taxes) associated with terminated international office space and incurred charges of $23 million ($16 million after income taxes) related to employee severance and other expenses.
- *Inventory write-off:* We incurred a pre-tax charge of $48 million ($30 million after income taxes) to write off surplus drilling materials based on future drilling plans and recognized a pre-tax charge of $39 million ($28 million after income taxes) to reduce crude oil inventories to their net realizable value.
- *Gain on asset sales, net:* We completed the sale of approximately 13,000 acres of Utica dry gas acreage for consideration of approximately $120 million. This transaction resulted in a pre-tax gain of $49 million ($31 million after income taxes). We also completed the sale of our producing assets in Algeria in December 2015 and recognized a pre-tax loss of $21 million ($21 million after income taxes).
- *Income taxes:* In 2015, we recorded net tax benefits totaling $101 million, comprised of $154 million to recognize a deferred tax benefit from a legal entity restructuring, $50 million benefit from receiving approval for an international investment incentive, a $9 million benefit from remeasuring deferred taxes for a change in the Norwegian enacted tax rates, and a $112 million charge to recognize a partial valuation allowance against foreign deferred tax assets.

*2014:*

- *Gain on asset sales, net:* We completed the sale of our producing assets in Thailand, 77,000 net acres of Utica dry gas acreage, including related wells and facilities, and an exploration asset in the United Kingdom North Sea. These divestitures generated total cash proceeds of $1,933 million and total pre-tax gains of $801 million ($774 million after income taxes). At the time of sale, these assets were producing at an aggregate net rate of approximately 19,000 boepd.
- *Dry hole, lease impairment and other exploration expenses:* We recorded dry hole and other exploration expenses for the write-off of a previously capitalized exploration well in the western half of Block 469 in the Gulf of Mexico of $169 million ($105 million after income taxes) and other charges totaling $135 million pre-tax ($68 million after income taxes) to write-off leasehold acreage in the Paris Basin of France, the Shakrok Block in Kurdistan and our interest in a natural gas exploration project, offshore Sabah, Malaysia.
- *Exit costs and other:* We recorded pre-tax severance and other exit costs of $28 million ($11 million after income taxes) resulting from our transformation to a more focused pure play E&P company.
- *Income taxes:* We recorded an income tax charge of $48 million for remeasurement of deferred taxes resulting from legal entity restructurings.

*2013:*

- *Gain on asset sales, net:* We completed the sale of the Natuna A Field in Indonesia, the Samara-Nafta Field in Russia, the Beryl Field in the United Kingdom and the Azeri-Chirag-Guneshli Field in Azerbaijan. Before allowing for the share of noncontrolling interests, these divestitures generated total cash proceeds of $4,099 million and total pre-tax gains of $2,195 million ($2,145 million after income taxes). At the time of sale, these assets were producing at an aggregate net rate of approximately 72,000 boepd.

- *Noncontrolling interest share of gain on asset sale:* The gain arising from the sale of Samara-Nafta was reduced by $168 million for the noncontrolling interest holder's share of the gain.
- *Impairment:* We incurred impairment charges of $289 million ($187 million after income taxes) related to the Pangkah Field to adjust its carrying value to its fair value at December 31, 2013.
- *Dry hole, lease impairment and other exploration expenses:* We recorded dry hole costs of $260 million ($163 million after income taxes) associated with the write-off of two previously drilled discovery wells in Area 54, offshore Libya due to continued civil unrest in the country and we recognized a charge of $38 million ($23 million after income taxes) to write-off certain onshore leasehold acreage in the U.S.
- *Exit costs and other:* We recorded net pre-tax charges of $129 million ($117 million after income taxes) for severance, non-cash charges associated with the cessation of use of certain leased office space and other exit costs, resulting from our planned divestitures and transformation into a more focused pure play E&P company.
- *Income taxes:* In December 2013, the country of Denmark enacted a new hydrocarbon income tax law that resulted in a combination of changes to tax rates, revisions to the amount of uplift allowed on capital expenditures and special transition rules. As a consequence of the tax law change, we recorded a deferred tax asset of $674 million. In addition we recorded non-cash income tax charges totaling $50 million related to a planned asset divestiture and the repatriation of foreign earnings.

***Bakken Midstream***

Net income (loss) of our Bakken Midstream operating segment, which is primarily located in North Dakota, is summarized as follows:

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In millions) | |
| Revenues and Non-operating Income | | | |
| Total revenues and non-operating income | **$ 564** | $ 319 | $ 270 |
| Costs and Expenses | | | |
| Cost of products sold (excluding items shown separately below) | **—** | — | 190 |
| Operating costs and expenses | **265** | 219 | 249 |
| General and administrative expenses | **14** | 11 | 15 |
| Depreciation, depletion and amortization | **88** | 70 | 33 |
| Interest expense | **10** | 2 | — |
| Total costs and expenses | **377** | 302 | 487 |
| Results of operations before income taxes | **187** | 17 | (217) |
| Provision (benefit) for income taxes | **52** | 7 | (81) |
| Net income (loss) | **135** | 10 | (136) |
| Less: Net income (loss) attributable to noncontrolling interests | **49** | — | — |
| Net income (loss) attributable to Hess Corporation | **$ 86** | $ 10 | $ (136) |

Total revenues and non-operating income in 2015 improved from 2014 mainly due to higher throughput volumes at the Tioga gas plant. In the fourth quarter of 2013, the Tioga gas plant was shut down for a large-scale expansion, refurbishment and optimization project, during which a new cryogenic processing train was installed and processing capacity was increased to 250 mmcfd from 120 mmcfd. The Tioga gas plant's expanded operations commenced in late March 2014. Total revenues and non-operating income for 2014 improved from 2013 as a result of tariff arrangements becoming effective in 2014. These arrangements allow for Bakken Midstream operating segment to charge a fee based tariff to Exploration and Production for certain Midstream services provided. Prior to 2014, when providing natural gas processing services, our Bakken Midstream operating segment 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. In addition, total revenues and non-operating income for 2014 also benefited from the large-scale expansion, refurbishment and optimization project at the Tioga gas plant which resulted in a shut-down of the plant from November 2013 to March 2014.

Operating costs and expenses were higher in 2015 compared to 2014 mainly due to an increase in third-party operating and maintenance expense. Operating costs and expenses were lower in 2014 compared to 2013 primarily as a result of a reduction in activity following the shutdown of the Tioga gas plant between November 2013 and March 2014. Depreciation, depletion and amortization (DD&A) expenses were higher in 2015 compared with 2014, primarily due to a full year's usage of the Tioga gas plant in 2015. DD&A expenses were higher in 2014 compared to 2013, primarily due to the commencement of depreciation of the Tioga gas plant expansion expenditures upon restart of operations in late March 2014.

For 2016, we estimate Net income attributable to Hess Corporation from the Bakken Midstream segment, excluding items affecting comparability of earnings between periods, to be in the range of $40 million to $50 million.

***Corporate, Interest and Other***

The following table summarizes Corporate, Interest and Other expenses:

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In millions) | |
| Corporate and other expenses (excluding items affecting comparability) | **$ 219** | $ 217 | $ 263 |
| Interest expense | **376** | 397 | 466 |
| Less: Capitalized interest | **(45)** | (76) | (60) |
| Interest expense, net | **331** | 321 | 406 |
| Corporate, Interest and Other expenses before income taxes | **550** | 538 | 669 |
| Provision (benefit) for income taxes | **(217)** | (208) | (252) |
| Net Corporate, Interest and Other expenses after income taxes | **333** | 330 | 417 |
| Items affecting comparability of earnings between periods, after-tax | **44** | 74 | 26 |
| Total Corporate, Interest and Other expenses after income taxes | **$ 377** | $ 404 | $ 443 |

Corporate and other expenses for 2014 include a pre-tax gain of $13 million ($8 million after income taxes) related to the disposition of our 50% interest in a joint venture involved in the construction of an electric generating facility in Newark, New Jersey. Excluding the gain, 2015 costs are down compared to 2014 primarily due to lower employee costs and other expenses. Corporate expenses were lower in 2014 compared to 2013, reflecting lower employee related costs, contract labor and professional fees. In 2016 after-tax corporate expenses, excluding items affecting comparability of earnings between periods, are estimated to be in the range of $110 million to $120 million.

Interest expense was lower in 2015 compared to 2014, as lower interest rates offset higher average borrowings. Capitalized interest was also lower in 2015 compared to 2014 due to the cessation of capitalized interest on the Tubular Bells Field upon first production in the fourth quarter of 2014. Interest expense, net was lower in 2014 compared to 2013, reflecting lower average outstanding debt, lower letter of credit fees and higher capitalized interest. In 2016 after-tax interest expense is estimated to be in the range of $205 million to $215 million.

***Items Affecting Comparability of Earnings Between Periods:*** In 2015 we recorded a pre-tax charge of $76 million ($49 million after income taxes) associated with debtor-in-possession financing provided to HOVENSA LLC and the estimated liability resulting from its bankruptcy resolution. See *Item 3. Legal Proceedings*. In 2015, we also incurred exit costs of $6 million ($4 million after income taxes) and recorded a pre-tax gain of $20 million ($13 million after income taxes) from the sale of land. In 2014 we recorded pre-tax charges of $84 million ($52 million after income taxes) to reduce the carrying value of our investment in the Bayonne Energy Center to fair value, $19 million ($12 million after income taxes) for net pre-tax severance charges and $15 million ($10 million after income taxes) for exit related costs. In 2013 we recorded pre-tax charges of $21 million ($13 million after income taxes) for severance charges related to our transformation into a pure play E&P company and $19 million ($13 million after income taxes) for exit related costs, including costs for cessation of leased office space.

***Discontinued Operations***

Discontinued operations attributable to Hess Corporation were a net loss of $48 million in 2015 compared to net income of $625 million in 2014 and $1,192 million in 2013. Discontinued operations included ownership of an energy trading partnership through February 2015, retail marketing through September 2014, terminals through December 2013, energy marketing through November 2013 and Port Reading refining activities through the date it was permanently shut down in February 2013.

***Items Affecting Comparability of Earnings Between Periods:*** In September 2014, we completed the sale of our retail business for cash proceeds of approximately $2.8 billion. This transaction resulted in a pre-tax gain of $954 million ($602 million after income taxes). During 2014, we recorded pre-tax gains of $275 million ($171 million after income taxes) relating to the liquidation of last-in, first-out (LIFO) inventories associated with the divested downstream operations. In addition, we recorded pre-tax charges totaling $308 million ($202 million after income taxes) in 2014 for impairments, environmental matters, severance and exit related activities associated with the divestiture of downstream operations. We also recognized in 2014 a pre-tax charge of $115 million ($72 million after income taxes) related to the termination of lease contracts and the purchase of 180 retail gasoline stations in preparation for the sale of the retail operations. In January 2014, we acquired our partners' 56% interest in WilcoHess, a retail gasoline joint venture, for approximately $290 million and the settlement of liabilities. In connection with this business combination, we recorded a pre-tax gain of $39 million ($24 million after income taxes) to remeasure the carrying value of our original 44% equity interest in WilcoHess to fair value. The assets and liabilities acquired from WilcoHess were included in the sale of the retail business in September 2014. In December 2013, we sold our U.S. East Coast terminal network, St. Lucia terminal and related businesses for cash proceeds of approximately $1.0 billion. The transaction resulted in a pre-tax gain of $739 million ($531 million after income taxes). In November 2013, we sold our energy marketing business for cash proceeds of approximately $1.2 billion which resulted in a pre-tax gain of $761 million ($464 million after income taxes). In addition, we recognized pre-tax gains of $678 million ($414 million after income taxes) relating to the liquidation of LIFO inventories as a result of ceasing refining operations and the sales of our energy marketing and terminals businesses. During 2013, we also incurred $131 million ($80 million after income taxes) of net employee severance charges and $230 million ($154 million after income taxes) of other exit costs, including environmental, legal and professional fees. As a result of the permanent shutdown of the Port Reading refining facility, we recorded charges of $82 million ($49 million after income taxes) for shutdown related costs and $80 million ($51 million after income taxes) for asset impairments.

## Liquidity and Capital Resources

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

| | December 31, 2015 | December 31, 2014 |
|---|---|---|
| | (In millions, except ratio) | |
| Cash and cash equivalents | **$ 2,716** | $ 2,444 |
| Current maturities of long-term debt | **86** | 68 |
| Total debt (a) | **6,630** | 5,987 |
| Total equity | **20,401** | 22,320 |
| Debt to capitalization ratio (b) | **24.5%** | 21.2% |

*(a) Includes $710 million of debt outstanding from our Bakken Midstream joint venture at December 31, 2015.*
*(b) Total debt as a percentage of the sum of total debt plus equity.*

### Cash Flows

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

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In millions) | |
| **Cash flows from operating activities:** | | | |
| Cash provided by (used in) operating activities - continuing operations | **$ 2,016** | $ 4,504 | $ 3,936 |
| Cash provided by (used in) operating activities - discontinued operations | **(35)** | (47) | 1,162 |
| Net cash provided by (used in) operating activities | **1,981** | 4,457 | 5,098 |
| **Cash flows from investing activities:** | | | |
| Additions to property, plant and equipment - E&P | **(3,956)** | (4,867) | (5,413) |
| Additions to property, plant and equipment - Bakken Midstream | **(365)** | (347) | (524) |
| Proceeds from asset sales | **50** | 2,978 | 4,458 |
| Other, net | **(44)** | (192) | (285) |
| Cash provided by (used in) investing activities - continuing operations | **(4,315)** | (2,428) | (1,764) |
| Cash provided by (used in) investing activities - discontinued operations | **109** | 2,436 | 2,114 |
| Net cash provided by (used in) investing activities | **(4,206)** | 8 | 350 |
| **Cash flows from financing activities:** | | | |
| Cash provided by (used in) financing activities - continuing operations | **2,497** | (3,828) | (4,266) |
| Cash provided by (used in) financing activities - discontinued operations | **—** | (7) | (10) |
| Net cash provided by (used in) financing activities | **2,497** | (3,835) | (4,276) |
| Net increase (decrease) in cash and cash equivalents from continuing operations | **198** | (1,752) | (2,094) |
| Net increase (decrease) in cash and cash equivalents from discontinued operations | **74** | 2,382 | 3,266 |
| **Net increase (decrease) in cash and cash equivalents** | **$ 272** | $ 630 | $ 1,172 |

***Operating Activities*****:** Net cash provided by operating activities declined to $1,981 million in 2015 (2014: $4,457 million), primarily reflecting the decline in benchmark crude oil prices. Net cash provided by operating activities declined to $4,457 million in 2014 (2013: $5,098 million), reflecting the impact of changes in working capital, lower operating earnings primarily as a result of asset sales, and the decline in benchmark crude oil prices.

***Investing Activities:*** The decrease in Additions to property, plant and equipment in 2015, as compared to 2014, is primarily due to reduced drilling activity (the Bakken, the Utica, Norway and Equatorial Guinea), reduced development expenditures at Tubular Bells and the JDA, and lower exploratory drilling activity (Ghana and Kurdistan). These reductions were offset by 2015 activity related to development activities at Stampede in the Gulf of Mexico and exploration drilling activity in the Gulf of Mexico and Guyana, and full field development at North Malay Basin.

The decrease in Additions to property, plant and equipment in 2014, as compared with 2013, is largely due to the ongoing reduction in capital expenditures in the Bakken, reflecting lower well costs, and completion of the Tioga gas plant expansion project.

Total proceeds from the sale of assets related to continuing operations amounted to $50 million in 2015 (2014: $2,978 million; 2013: $4,458 million). In 2014, we completed asset sales of our dry gas acreage in the Utica shale play, our assets in Thailand, the Pangkah Field, offshore Indonesia, and our interests in two power plant joint ventures. Completed sales in 2013 included our interests in the Beryl, ACG, Eagle Ford and Natuna A fields, and our Russian subsidiary, Samara-Nafta.

In 2014, net cash provided by investing activities from discontinued operations included proceeds of $2.8 billion from the sale of the retail business. In addition, we acquired in January 2014, our partners' 56% interest in WilcoHess, a retail gasoline joint venture, for approximately $290 million. In June 2014, we incurred capital expenditures of $105 million related to the acquisition of previously leased retail gasoline stations. Both of these transactions were undertaken in connection with our divestiture of our retail business. Net cash provided by investing activities related to discontinued operations for 2013 includes proceeds of approximately $2.2 billion from the sales of our energy marketing operations and our U.S. East Coast terminal network, St. Lucia terminal and related businesses.

***Financing Activities:*** During 2015, we received net cash consideration of approximately $2.6 billion from the sale of a 50% interest in our Bakken Midstream business. Upon formation of the joint venture, HIP issued $600 million of debt under a Term Loan A facility. The proceeds from the debt were distributed equally to the partners. During 2014, we issued $600 million ($598 million net of discount) of unsecured, fixed rate notes and repaid $590 million of debt, including $250 million of unsecured, fixed rate notes, $74 million assumed in the acquisition of WilcoHess, and $249 million for the payment of various lease obligations primarily related to the retirement of our retail gasoline station leases. In 2013, we repaid $2,348 million, net under available credit facilities and repaid $136 million of other debt. The net repayments under the credit facilities consisted of $990 million on our short-term credit facilities, $758 million on our syndicated revolving credit facility and $600 million on our asset backed credit facility.

In 2015, we paid $142 million for the purchase and settlement of common shares under our $6.5 billion Board authorized stock repurchase plan (2014: $3,715 million; 2013: $1,493 million). Total common stock dividends paid were $287 million in 2015 (2014: $303 million; 2013: $235 million). We received net proceeds from the exercise of stock options, including related income tax benefits of $12 million in 2015 (2014: $182 million; 2013: $128 million).

**Future Capital Requirements and Resources**

At December 31, 2015, we had $2.7 billion in cash and cash equivalents, including $0.4 billion held outside of the U.S. which we have the ability to repatriate without triggering a U.S. cash tax liability, 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 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, 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*.

The table below summarizes the capacity, usage, and available capacity of our borrowing and letter of credit facilities at December 31, 2015:

| | Expiration Date | Capacity | Borrowings | Letters of Credit Issued | Total Used | Available Capacity |
|---|---|---|---|---|---|---|
| | | | | (In millions) | | |
| Revolving credit facility - Hess Corporation | January 2020 | $ 4,000 | $ — | $ — | $ — | $ 4,000 |
| Revolving credit facility - Bakken Midstream (a) | July 2020 | 400 | 110 | — | 110 | 290 |
| Committed lines | Various (b) | 650 | — | 10 | 10 | 640 |
| Uncommitted lines | Various (b) | 103 | — | 103 | 103 | — |
| Total | | $ 5,153 | $ 110 | $ 113 | $ 223 | $ 4,930 |

*(a) The Revolving credit facility – Bakken Midstream may only be utilized by Hess Infrastructure Partners.*
*(b) Committed and uncommitted lines have expiration dates through 2016.*

We had $113 million in letters of credit outstanding at December 31, 2015 (2014: $397 million), which in 2015 primarily relate to our international operations. See also *Note 22, Financial Risk Management Activities* in the *Notes to the Consolidated Financial Statements.*

In January 2015, we entered into a $4 billion syndicated revolving credit facility that expires in January 2020. The new facility, which replaced a $4 billion facility that was scheduled to expire in April 2016, can be used for borrowings and letters of credit. Based on our credit rating as of December 31, 2015, borrowings on the facility will generally bear interest at 1.075% above the London Interbank Offered Rate (LIBOR). A fee of 0.175% per annum is also payable on the amount of the facility. The interest rate and facility fee will be higher if our credit rating is lowered.

Our long-term debt agreements, including the revolving credit facilities, contain financial covenants that restrict the amount of total borrowings and secured debt. The most restrictive of these covenants allow us to borrow up to an additional $5,495 million of secured debt at December 31, 2015.

In July 2015, HIP, a 50/50 joint venture between us and GIP, incurred $600 million of debt through a 5-year Term Loan A facility. The proceeds from the debt were distributed equally to the partners. HIP also entered into a $400 million 5-year syndicated revolving credit facility, which can be used for borrowings and letters of credit and is expected to fund the joint venture's operating activities and capital expenditures. Borrowings on both loan facilities generally bear interest at the LIBOR plus an applicable margin ranging from 1.10% to 2.00%. Facility fees on the revolving credit facility accrue at an applicable rate every quarter, ranging from 0.15% to 0.35% per annum. The interest rate and facility fee are subject to adjustment based on the joint venture's leverage ratio, which is calculated as total debt to Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA). If the joint venture obtains credit ratings, pricing levels will be based on the credit ratings in effect from time to time. The joint venture's credit facilities contain financial covenants that generally require a leverage ratio of no more than 5.0 to 1.0 for the prior four fiscal quarters and an interest coverage ratio, which is calculated as EBITDA to interest expense, of no less than 2.25 to 1.0 for the prior four fiscal quarters.

At December 31, 2015, borrowings attributable to the joint venture, which are non-recourse to Hess Corporation, amounted to $600 million on the Term Loan A loan facility and $110 million on the revolving credit facility. HIP is in compliance with all debt covenants at December 31, 2015, and its financial covenants do not currently impact their ability to issue indebtedness to fund future capital expenditures.

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

***Credit Ratings***

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. The consequence of lower credit ratings is to increase interest rates and facility fees on our credit facilities. In addition, we have contractual requirements to provide collateral to certain counterparties when one rating agency rates our unsecured debt below investment grade. Due to the recent rating change by Moody's we may be required to issue collateral in the form of letters of credit up to approximately $200 million. Certain other contracts require we provide collateral when two of three rating agencies rate us below investment grade. If Fitch or S&P were to reduce their rating on our unsecured debt below investment grade, we estimate that we could be required to issue letters of credit up to an additional $200 million as of December 31, 2015.

***Contractual Obligations and Contingencies***

The following table shows aggregate information about certain contractual obligations at December 31, 2015:

| | | Payments Due by Period | | | |
|---|---|---|---|---|---|
| | **Total** | **2016** | **2017 and 2018** | **2019 and 2020** | **Thereafter** |
| | | | **(In millions)** | | |
| Total debt (excludes interest) (a) | $ 6,630 | $ 86 | $ 535 | $ 1,681 | $ 4,328 |
| Operating leases | 2,445 | 674 | 925 | 473 | 373 |
| Purchase obligations: | | | | | |
| Capital expenditures | 1,750 | 1,503 | 247 | — | — |
| Operating expenses | 548 | 384 | 108 | 32 | 24 |
| Transportation and related contracts | 1,598 | 121 | 453 | 433 | 591 |
| Asset retirement obligations | 2,383 | 225 | 608 | 307 | 1,243 |
| Other liabilities | 1,160 | 66 | 120 | 123 | 851 |

*(a) We anticipate cash payments for interest of $391 million for 2016, $789 million for 2017-2018, $644 million for 2019-2020, and $3,988 million thereafter for a total of $5,812 million.*

Capital expenditures represent amounts that were contractually committed at December 31, 2015, including the portion of our planned capital expenditure program for 2016. Obligations for operating expenses include commitments for oil and gas production expenses, seismic purchases and other normal business expenses. Other long-term liabilities reflect contractually committed obligations in the *Consolidated Balance Sheet* at December 31, 2015, including pension plan liabilities and estimates for uncertain income tax positions.

The Corporation and certain of its subsidiaries, lease drilling rigs, tankers, office space and other assets for varying periods under leases accounted for as operating leases.

**Off-Balance Sheet Arrangements**

At December 31, 2015, we have $32 million in letters of credit for which we are contingently liable. See also *Note 19, Guarantees, Contingencies and Commitments* in the *Notes to the Consolidated Financial Statements*.

**Foreign Operations**

We conduct exploration and production activities outside the U.S., principally in Europe (Norway and Denmark), Africa (Equatorial Guinea, Libya, and Ghana) and Asia and Other (Joint Development Area of Malaysia/Thailand, Malaysia, Australia, Guyana and Canada). Therefore, we are subject to the risks associated with foreign operations, including political risk, corruption, acts of terrorism, tax law changes and currency risk. See *Item 1A. Risk Factors* for further details.

**Critical Accounting Policies and Estimates**

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

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

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

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

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

Proved reserves are calculated using the average price during the twelve month period ending December 31 determined as an unweighted arithmetic average of the price on the first day of each month within the year, unless prices are defined by contractual agreements, excluding escalations based on future conditions. As discussed in *Item 1A. Risk Factors*, crude oil prices are volatile which can have an impact on our proved reserves. For example, the average West Texas Intermediate (WTI) crude oil price used in the determination of proved reserves at December 31, 2015 and 2014 was $50.13 and $94.42 per barrel, respectively. The drop in prices for 2015 resulted in negative revisions to our proved reserves at December 31, 2015 of 234 million barrels of oil equivalent, primarily related to proved undeveloped reserves. At December 31, 2015, spot prices for WTI crude oil closed at $37.13 per barrel and averaged $31.78 per barrel in January 2016. If crude oil prices in 2016 stay at levels below that used in determining 2015 proved reserves, we may recognize further negative revisions up to a significant majority of our December 31, 2015 proved undeveloped reserves. In addition, we may recognize negative revisions to proved developed reserves, which can vary significantly by asset due to differing operating cost structures. Conversely, price increases in 2016 above those used in determining 2015 proved reserves could result in positive revisions to proved developed and proved undeveloped reserves at December 31, 2016. It is difficult to estimate the magnitude of any potential net negative or positive change in proved reserves as of December 31, 2016, due to a number of factors that are currently unknown, including 2016 crude oil prices, any revisions based on 2016 reservoir performance, and the levels to which industry costs will change in response to movements in commodity prices. A 10% change in proved developed and proved undeveloped reserves at December 31, 2015 would result in an approximate $350 million pre-tax change in depreciation, depletion, and amortization expense for 2016. See the *Supplementary Oil and Gas Data* on pages 85 through 89 in the accompanying financial statements for additional information on our oil and gas reserves.

***Bakken Midstream Joint Venture:*** On July 1, 2015 we sold a 50% interest in Hess Infrastructure Partners LP (HIP) to Global Infrastructure Partners (GIP) for net cash consideration of approximately $2.6 billion. We consolidate the activities of

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

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

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

Our impairment tests of long-lived E&P producing assets are based on our best estimates of future production volumes (including recovery factors), selling prices, operating and capital costs, the timing of future production and other factors, which are updated each time an impairment test is performed. We could have impairments if the projected production volumes from oil and gas fields decrease, crude oil and natural gas selling prices decline significantly for an extended period or future estimated capital and operating costs increase significantly. As a result of the extended period of low crude oil prices, we tested our oil and gas properties for impairment. See *Note 10, Impairment* in the *Notes to the Consolidated Financial Statements*.

***Impairment of Goodwill:*** Goodwill is tested for impairment annually on October 1 or when events or circumstances indicate that the carrying amount of the goodwill may not be recoverable based on a two-step process. The goodwill test is conducted at a reporting unit level, which is defined in accounting standards as an operating segment or one level below an operating segment. The reporting unit or units to be used in an evaluation and measurement of goodwill for impairment testing are determined from a number of factors, including the manner in which the business is managed. Prior to the second quarter of 2015, we had one operating segment, E&P consisting of two reporting units, Offshore and Onshore which reflected the manner in which performance was assessed by the Operating segment manager. In the second quarter of 2015 we established a second operating segment, Bakken Midstream, which previously was part of the Onshore reporting unit. Prior to the formation of the Bakken Midstream operating segment the Offshore reporting unit had allocated goodwill of $1,098 million while the Onshore reporting unit had allocated goodwill of $760 million. Upon formation of the Bakken Midstream operating segment, we allocated $375 million of goodwill from the Onshore reporting unit to the Bakken Midstream operating segment based on the relative fair values of the Bakken Midstream business and the remainder of the Onshore reporting unit. There was no change to the composition of the Offshore reporting unit.

In step one of the impairment test, the fair value of a reporting unit is compared with its carrying amount, including goodwill. If the fair value of the reporting unit exceeds its carrying value, goodwill is not impaired. If the carrying value of the reporting unit exceeds its fair value, we perform step two to determine possible impairment by comparing the implied fair value of goodwill with the carrying amount. The implied fair value of goodwill is determined by assuming the reporting unit is purchased at fair value with assets and liabilities of the reporting unit being reflected at fair value in the same manner as the accounting prescribed for a business combination. The resulting excess of fair value of the reporting unit over the amounts assigned to the reporting unit's assets and liabilities represents the implied fair value of goodwill. If the implied fair value of goodwill is less than its carrying amount, an impairment loss would be recorded.

Our fair value estimate of each reporting unit is the sum of the anticipated discounted cash flows of producing assets and known development projects and an estimated market premium to reflect the market price an acquirer would pay for potential synergies including cost savings, access to new business opportunities, enterprise control and increased market share. The determination of the fair value of each reporting unit depends on estimates about oil and gas reserves, future prices, timing of future net cash flows and market premiums. We also consider the relative market valuation of similar peer companies, and other market data if available, in determining fair value of a reporting unit. In addition, a qualitative reconciliation of our market capitalization to the fair value of the reporting units used in the goodwill impairment test is performed as of the testing date to assess reasonableness of the reporting unit fair values.

Significant extended declines in crude oil and natural gas prices or reduced reserve estimates could lead to a decrease in the fair value of a reporting unit that could result in failing step one and potentially result in an impairment of goodwill based on the outcome of step two. If a reporting unit fails step one, it is possible that the implied fair value of goodwill in step two exceeds its carrying value due to one or more assets of the reporting unit having a fair value below its carrying value.

As there are significant differences in the way long-lived assets and goodwill are evaluated and measured for impairment testing, there may be impairments of individual assets that would not cause an impairment of the goodwill assigned at the reporting unit level or there could be an impairment of goodwill without a corresponding impairment of an underlying asset.

In the second quarter of 2015, we performed impairment tests on the Offshore and Onshore reporting units in accordance with accounting standards for goodwill immediately prior to creation of the Bakken Midstream operating segment. No impairment resulted from this assessment. In addition, accounting standards require that following a reorganization, allocated goodwill should be tested for impairment. We also performed impairment tests on the allocated goodwill for the Bakken Midstream and the Onshore reporting unit at June 30, 2015. Goodwill allocated to the Bakken Midstream operating segment passed the impairment test but the goodwill allocated to the Onshore reporting unit did not pass the impairment test. As a result, we recorded a noncash pre-tax charge of $385 million ($385 million after income taxes) in the second quarter of 2015 to reflect the Onshore reporting unit's goodwill at its implied fair value of zero based on a hypothetical purchase price allocation as stipulated in the accounting standards.

As a result of the decline in crude oil prices in the fourth quarter of 2015, we performed an impairment test at December 31, 2015 on the Offshore reporting unit and determined its goodwill was impaired. We recorded a pre-tax impairment charge of $1,098 million ($1,098 million after income taxes) to reflect the Offshore reporting unit's goodwill at its implied fair value of zero based on a hypothetical purchase price allocation as stipulated in the accounting standards. We expect that the benefits of our remaining goodwill totaling $375 million will be recovered through the Bakken Midstream operating segment based on market conditions at December 31, 2015.

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

We have net operating loss carryforwards or credit carryforwards in multiple jurisdictions and have recorded deferred tax assets for those losses and credits. Additionally, we have deferred tax assets due to temporary differences between the book basis and tax basis of certain assets and liabilities. We have net deferred tax assets of $2,653 million recognized in the *Consolidated Balance Sheet* at December 31, 2015. Regular assessments are made as to the likelihood of those deferred tax assets being realized. If it is more likely than not that some or all of the deferred tax assets will not be realized, a valuation allowance is recorded to reduce the deferred tax assets to the amount that is expected to be realized. In evaluating the realizability of deferred tax assets, we consider the reversal of temporary differences, the expected utilization of net operating losses and credit carryforwards during available carryforward periods, the availability of tax planning strategies, the existence of appreciated assets and estimates of future taxable income and other factors. Estimates of future taxable income are based on assumptions of oil and gas reserves and selling prices that are consistent with our internal business forecasts. Additional valuation allowances may be required if internal business forecasts adopt lower selling price assumptions or development plans. We do not provide for deferred U.S. income taxes for that portion of undistributed earnings of foreign subsidiaries that are indefinitely reinvested in foreign operations.

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

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

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

***Derivatives:*** We utilize derivative instruments, including futures, forwards, options and swaps, individually or in combination to mitigate our exposure to fluctuations in the prices of crude oil and natural gas, as well as changes in interest and foreign currency exchange rates.

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

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

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

We determine fair value in accordance with the fair value measurements accounting standard which established a hierarchy for the inputs used to measure fair value based on the source of the inputs, which generally range from quoted prices for identical instruments in a principal trading market (Level 1) to estimates determined using related market data (Level 3), including discounted cash flows and other unobservable data. Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2.

When Level 1 inputs are available within a particular market, those inputs are selected for determination of fair value over Level 2 or 3 inputs in the same market. Multiple inputs may be used to measure fair value; however, the level of fair value for each physical derivative and financial asset or liability is based on the lowest significant input level within this fair value hierarchy.

**Environment, Health and Safety**

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

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

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

We accrue for environmental assessment and remediation expenses when the future costs are probable and reasonably estimable. At December 31, 2015, our reserve for estimated remediation liabilities was approximately $80 million. We expect that existing reserves for environmental liabilities will adequately cover costs to assess and remediate known sites. Our remediation spending was approximately $13 million in 2015 (2014: $12 million; 2013: $16 million). The level of other expenditures to comply with federal, state, local and foreign country environmental regulations is difficult to quantify as such costs are captured as mostly indistinguishable components of our capital expenditures and operating expenses.

**Item 7A. Quantitative and Qualitative Disclosures About Market Risk**

As discussed in *Note 22, Financial Risk Management Activities*, in the *Notes to the Consolidated Financial Statements*, in the normal course of our business, we are exposed to commodity risks related to changes in the prices of crude oil and natural gas as well as changes in interest rates and foreign currency values. In the disclosures that follow, financial risk management activities refer to the mitigation of these risks through hedging activities. We were exposed to commodity price risks primarily related to crude oil, natural gas, refined petroleum products and electricity, as well as foreign currency values, from our 50% voting interest in a consolidated energy trading joint venture, HETCO, which was sold in the first quarter of 2015.

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

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

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

**Financial Risk Management Activities**

Financial risk management activities include transactions designed to reduce risk in the selling prices of crude oil or natural gas produced by us or to reduce exposure to foreign currency or interest rate movements. Generally, futures, swaps or option strategies may be used to reduce risk in the selling price of a portion of our crude oil or natural gas production. Forward contracts may also be used to purchase certain currencies in which we do business with the intent of reducing exposure to foreign currency fluctuations. Interest rate swaps may also be used, generally to convert fixed-rate interest payments to floating.

We have outstanding foreign exchange contracts used to reduce our exposure to fluctuating foreign exchange rates for various currencies. The change in fair value of foreign exchange contracts from a 10% weakening of the U.S. Dollar exchange rate is estimated to be a loss of approximately $95 million at December 31, 2015.

At December 31, 2015, our outstanding long-term debt of $6,630 million, including current maturities, had a fair value of $6,515 million. A 15% increase or decrease in the rate of interest would decrease or increase the fair value of debt by approximately $410 million or $480 million, respectively.

**Trading Activities**

In February 2015, we sold our interest in our energy trading joint venture, HETCO, which was subsequently renamed Hartree Partners, LP (Hartree). Pursuant to the terms of the sale, Hartree was permitted to utilize our guarantees issued in favor of Hartree's existing counterparties until November 12, 2015, provided that new trades were for a period of one year or less, complied with certain credit requirements, and net exposures remained within value at risk limits previously applied by us. The guarantees remain in effect until the qualifying trades outstanding at November 12, 2015 mature. We have the right to seek reimbursement from Hartree and a separate Hartree credit support facility upon any counterparty draw on the applicable guarantee from us. No draws on the guaranteed trades have occurred through December 31, 2015. A liability of $10 million associated with the guarantee is included in other accrued liabilities at December 31, 2015. At December 31, 2014, HETCO assets totaling $1,035 million, consisting of accounts receivable and other long-lived assets, were reported in Other current assets, and liabilities totaling $797 million, which consisted primarily of accounts payable, were reported in Accrued liabilities in the *Consolidated Balance Sheet*.

**Item 8. Financial Statements and Supplementary Data**

## HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
## INDEX TO FINANCIAL STATEMENTS AND SCHEDULE



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

**Management's Report on Internal Control over Financial Reporting**

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2015.

The Corporation's independent registered public accounting firm, Ernst & Young LLP, has audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2015, as stated in their report, which is included herein.

| | | | |
|---|---|---|---|
| By | /s/ John P. Rielly | By | /s/ John B. Hess |
| | John P. Rielly<br>Senior Vice President and<br>Chief Financial Officer | | John B. Hess<br>Chief Executive Officer |

February 25, 2016

## Report of Independent Registered Public Accounting Firm

**The Board of Directors and Stockholders**
**Hess Corporation**

We have audited Hess Corporation and consolidated subsidiaries' (the "Corporation") internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). The Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Corporation's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Hess Corporation and consolidated subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Hess Corporation and consolidated subsidiaries as of December 31, 2015 and 2014, and the related statements of consolidated income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2015 of Hess Corporation and consolidated subsidiaries, and our report dated February 25, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
New York, New York
February 25, 2016

## Report of Independent Registered Public Accounting Firm

**The Board of Directors and Stockholders**
**Hess Corporation**

We have audited the accompanying consolidated balance sheets of Hess Corporation and consolidated subsidiaries (the "Corporation") as of December 31, 2015 and 2014, and the related statements of consolidated income, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Hess Corporation and consolidated subsidiaries at December 31, 2015 and 2014, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Hess Corporation's internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 25, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
New York, New York
February 25, 2016

## HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

## CONSOLIDATED BALANCE SHEET

| | December 31, 2015 | December 31, 2014 |
|---|---|---|
| | (In millions, except share amounts) | |
| **ASSETS** | | |
| Current Assets: | | |
| Cash and cash equivalents | $ **2,716** | $ 2,444 |
| Accounts receivable | | |
| Trade | **847** | 1,642 |
| Other | **312** | 431 |
| Inventories | **399** | 527 |
| Other current assets | **130** | 1,269 |
| Total current assets | **4,404** | 6,313 |
| Property, plant and equipment: | | |
| Total — at cost | **46,826** | 46,522 |
| Less: Reserves for depreciation, depletion, amortization and lease impairment | **20,474** | 19,005 |
| Property, plant and equipment — net | **26,352** | 27,517 |
| Goodwill | **375** | 1,858 |
| Deferred income taxes | **2,653** | 2,371 |
| Other assets | **411** | 348 |
| **TOTAL ASSETS** | $ **34,195** | $ 38,407 |
| **LIABILITIES** | | |
| Current Liabilities: | | |
| Accounts payable | $ **457** | $ 708 |
| Accrued liabilities | **1,997** | 3,781 |
| Taxes payable | **88** | 294 |
| Current maturities of long-term debt | **86** | 68 |
| Total current liabilities | **2,628** | 4,851 |
| Long-term debt | **6,544** | 5,919 |
| Deferred income taxes | **1,334** | 1,838 |
| Asset retirement obligations | **2,158** | 2,281 |
| Other liabilities and deferred credits | **1,130** | 1,198 |
| Total liabilities | **13,794** | 16,087 |
| **EQUITY** | | |
| Hess Corporation stockholders' equity | | |
| Common stock, par value $1.00 | | |
| Authorized — 600,000,000 shares | | |
| Issued — 286,045,586 shares at December 31, 2015 (2014: 285,834,964) | **286** | 286 |
| Capital in excess of par value | **4,127** | 3,277 |
| Retained earnings | **16,637** | 20,052 |
| Accumulated other comprehensive income (loss) | **(1,664)** | (1,410) |
| Total Hess Corporation stockholders' equity | **19,386** | 22,205 |
| Noncontrolling interests | **1,015** | 115 |
| Total equity | **20,401** | 22,320 |
| **TOTAL LIABILITIES AND EQUITY** | $ **34,195** | $ 38,407 |

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

See accompanying Notes to the Consolidated Financial Statements.

## HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

## STATEMENT OF CONSOLIDATED INCOME

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2015** | **2014** | **2013** |
| | (In millions, except per share amounts) | | |
| **Revenues and Non-Operating Income** | | | |
| Sales and other operating revenues | **$ 6,636** | $ 10,737 | $ 11,905 |
| Gains on asset sales, net | **51** | 823 | 2,174 |
| Other, net | **(126)** | (121) | (51) |
| Total revenues and non-operating income | **6,561** | 11,439 | 14,028 |
| **Costs and Expenses** | | | |
| Cost of products sold (excluding items shown separately below) | **1,294** | 1,719 | 1,725 |
| Operating costs and expenses | **2,029** | 2,034 | 2,244 |
| Production and severance taxes | **146** | 275 | 372 |
| Exploration expenses, including dry holes and lease impairment | **881** | 840 | 1,031 |
| General and administrative expenses | **557** | 588 | 673 |
| Interest expense | **341** | 323 | 406 |
| Depreciation, depletion and amortization | **3,955** | 3,224 | 2,687 |
| Impairment | **1,616** | — | 289 |
| Total costs and expenses | **10,819** | 9,003 | 9,427 |
| **Income (Loss) From Continuing Operations Before Income Taxes** | **(4,258)** | 2,436 | 4,601 |
| Provision (benefit) for income taxes | **(1,299)** | 744 | 565 |
| **Income (Loss) From Continuing Operations** | **(2,959)** | 1,692 | 4,036 |
| **Income (Loss) From Discontinued Operations, Net of Income Taxes** | **(48)** | 682 | 1,186 |
| **Net Income (Loss)** | **(3,007)** | 2,374 | 5,222 |
| Less: Net income (loss) attributable to noncontrolling interests | **49** | 57 | 170 |
| **Net Income (Loss) Attributable to Hess Corporation** | **$ (3,056)** | $ 2,317 | $ 5,052 |
| **Net Income (Loss) Attributable to Hess Corporation Per Share** | | | |
| **Basic:** | | | |
| Continuing operations | **$ (10.61)** | $ 5.57 | $ 11.47 |
| Discontinued operations | **(0.17)** | 2.06 | 3.54 |
| **Net Income (Loss) Per Share** | **$ (10.78)** | $ 7.63 | $ 15.01 |
| **Diluted:** | | | |
| Continuing operations | **$ (10.61)** | $ 5.50 | $ 11.33 |
| Discontinued operations | **(0.17)** | 2.03 | 3.49 |
| **Net Income (Loss) Per Share** | **$ (10.78)** | $ 7.53 | $ 14.82 |
| **Weighted Average Number of Common Shares Outstanding (Diluted)** | **283.6** | 307.7 | 340.9 |

See accompanying Notes to the Consolidated Financial Statements.

## HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

## STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (In millions) | | |
| **Net Income (Loss)** | **$ (3,007)** | $ 2,374 | $ 5,222 |
| **Other Comprehensive Income (Loss):** | | | |
| **Derivatives designated as cash flow hedges:** | | | |
| Effect of hedge (gains) losses reclassified to income | **(118)** | (137) | (33) |
| Income taxes on effect of hedge (gains) losses reclassified to income | **44** | 51 | 18 |
| Net effect of hedge (gains) losses reclassified to income | **(74)** | (86) | (15) |
| Change in fair value of cash flow hedges | **121** | 128 | 68 |
| Income taxes on change in fair value of cash flow hedges | **(45)** | (48) | (25) |
| Net change in fair value of cash flow hedges | **76** | 80 | 43 |
| Change in derivatives designated as cash flow hedges, after-tax | **2** | (6) | 28 |
| **Pension and other postretirement plans:** | | | |
| Reduction (increase) of unrecognized actuarial losses | **17** | (534) | 414 |
| Income taxes on actuarial changes in plan liabilities | **4** | 186 | (157) |
| Reduction (increase) in unrecognized actuarial losses, net | **21** | (348) | 257 |
| Amortization of net actuarial losses | **92** | 56 | 63 |
| Income taxes on amortization of net actuarial losses | **(31)** | (18) | (23) |
| Net effect of amortization of net actuarial losses | **61** | 38 | 40 |
| Recognition of accumulated actuarial losses - HOVENSA | **15** | — | — |
| Income taxes on recognition of accumulated actuarial losses - HOVENSA | **(9)** | — | — |
| Recognition of accumulated actuarial losses, net of tax - HOVENSA | **6** | — | — |
| Change in pension and other postretirement plans, after-tax | **88** | (310) | 297 |
| **Foreign currency translation adjustment:** | | | |
| Foreign currency translation adjustment | **(344)** | (756) | (283) |
| Reclassified to Gains on asset sales, net | **—** | — | 119 |
| Change in foreign currency translation adjustment | **(344)** | (756) | (164) |
| **Other Comprehensive Income (Loss)** | **(254)** | (1,072) | 161 |
| **Comprehensive Income (Loss)** | **(3,261)** | 1,302 | 5,383 |
| Less: Comprehensive income (loss) attributable to noncontrolling interests | **49** | 57 | 176 |
| **Comprehensive Income (Loss) Attributable to Hess Corporation** | **$ (3,310)** | $ 1,245 | $ 5,207 |

See accompanying Notes to the Consolidated Financial Statements.

**HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES**

**STATEMENT OF CONSOLIDATED CASH FLOWS**

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (In millions) | | |
| **Cash Flows From Operating Activities** | | | |
| Net income (loss) | **$ (3,007)** | $ 2,374 | $ 5,222 |
| Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities | | | |
| (Gains) losses on asset sales, net | **(51)** | (823) | (2,174) |
| Depreciation, depletion and amortization | **3,955** | 3,224 | 2,687 |
| Impairment | **1,616** | — | 289 |
| Loss from equity affiliates | **25** | 84 | — |
| Exploratory dry hole costs | **410** | 301 | 344 |
| Exploration lease impairment | **182** | 207 | 245 |
| Stock compensation expense | **97** | 87 | 60 |
| Provision (benefit) for deferred income taxes | **(1,319)** | 270 | (427) |
| (Income) loss from discontinued operations, net of income taxes | **48** | (682) | (1,186) |
| Changes in operating assets and liabilities | | | |
| (Increase) decrease in accounts receivable | **841** | (199) | (239) |
| (Increase) decrease in inventories | **29** | 62 | 134 |
| Increase (decrease) in accounts payable and accrued liabilities | **(424)** | 79 | (375) |
| Increase (decrease) in taxes payable | **(222)** | (108) | (435) |
| Changes in operating assets and liabilities | **(164)** | (372) | (209) |
| Cash provided by (used in) operating activities - continuing operations | **2,016** | 4,504 | 3,936 |
| Cash provided by (used in) operating activities - discontinued operations | **(35)** | (47) | 1,162 |
| Net cash provided by (used in) operating activities | **1,981** | 4,457 | 5,098 |
| **Cash Flows From Investing Activities** | | | |
| Additions to property, plant and equipment - E&P | **(3,956)** | (4,867) | (5,413) |
| Additions to property, plant and equipment - Bakken Midstream | **(365)** | (347) | (524) |
| Proceeds from asset sales | **50** | 2,978 | 4,458 |
| Other, net | **(44)** | (192) | (285) |
| Cash provided by (used in) investing activities - continuing operations | **(4,315)** | (2,428) | (1,764) |
| Cash provided by (used in) investing activities - discontinued operations | **109** | 2,436 | 2,114 |
| Net cash provided by (used in) investing activities | **(4,206)** | 8 | 350 |
| **Cash Flows From Financing Activities** | | | |
| Net borrowings (repayments) of debt with maturities of 90 days or less | **—** | — | (1,748) |
| Debt with maturities of greater than 90 days | | | |
| Borrowings | **710** | 598 | 535 |
| Repayments | **(67)** | (590) | (1,271) |
| Common stock acquired and retired | **(142)** | (3,715) | (1,493) |
| Cash dividends paid | **(287)** | (303) | (235) |
| Employee stock options exercised, including income tax benefits | **12** | 182 | 128 |
| Noncontrolling interests, net | **2,296** | — | (182) |
| Other, net | **(25)** | — | — |
| Cash provided by (used in) financing activities - continuing operations | **2,497** | (3,828) | (4,266) |
| Cash provided by (used in) financing activities - discontinued operations | **—** | (7) | (10) |
| Net cash provided by (used in) financing activities | **2,497** | (3,835) | (4,276) |
| **Net Increase (Decrease) In Cash and Cash Equivalents** | **272** | 630 | 1,172 |
| **Cash and Cash Equivalents at Beginning of Year** | **2,444** | 1,814 | 642 |
| **Cash and Cash Equivalents at End of Year** | **$ 2,716** | $ 2,444 | $ 1,814 |

See accompanying Notes to the Consolidated Financial Statements.

## HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

## STATEMENT OF CONSOLIDATED EQUITY

| | Common Stock | Capital in Excess of Par | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total Hess Stockholders' Equity | Noncontrolling Interests | Total Equity |
|---|---|---|---|---|---|---|---|
| | | | | (In millions) | | | |
| **Balance at January 1, 2013** | $ 342 | $ 3,524 | $ 17,717 | $ (493) | $ 21,090 | $ 113 | $ 21,203 |
| Net income (loss) | — | — | 5,052 | — | 5,052 | 170 | 5,222 |
| Other comprehensive income (loss) | — | — | — | 155 | 155 | 6 | 161 |
| Activity related to restricted common stock awards, net | 1 | 32 | — | — | 33 | — | 33 |
| Employee stock options, including income tax benefits | 2 | 137 | — | — | 139 | — | 139 |
| Performance share units | — | 10 | — | — | 10 | — | 10 |
| Common stock acquired and retired | (20) | (205) | (1,313) | — | (1,538) | — | (1,538) |
| Cash dividends declared | — | — | (235) | — | (235) | — | (235) |
| Noncontrolling interests, net | — | — | 14 | — | 14 | (225) | (211) |
| **Balance at December 31, 2013** | $ 325 | $ 3,498 | $ 21,235 | $ (338) | $ 24,720 | $ 64 | $ 24,784 |
| Net income (loss) | — | — | 2,317 | — | 2,317 | 57 | 2,374 |
| Other comprehensive income (loss) | — | — | — | (1,072) | (1,072) | — | (1,072) |
| Activity related to restricted common stock awards, net | 1 | 60 | — | — | 61 | — | 61 |
| Employee stock options, including income tax benefits | 3 | 182 | — | — | 185 | — | 185 |
| Performance share units | — | 19 | — | — | 19 | — | 19 |
| Common stock acquired and retired | (43) | (482) | (3,197) | — | (3,722) | — | (3,722) |
| Cash dividends declared | — | — | (303) | — | (303) | — | (303) |
| Noncontrolling interests, net | — | — | — | — | — | (6) | (6) |
| **Balance at December 31, 2014** | $ 286 | $ 3,277 | $ 20,052 | $ (1,410) | $ 22,205 | $ 115 | $ 22,320 |
| Net income (loss) | **—** | **—** | **(3,056)** | **—** | **(3,056)** | **49** | **(3,007)** |
| Other comprehensive income (loss) | **—** | **—** | **—** | **(254)** | **(254)** | **—** | **(254)** |
| Activity related to restricted common stock awards, net | **1** | **66** | **—** | **—** | **67** | **—** | **67** |
| Employee stock options, including income tax benefits | **—** | **15** | **—** | **—** | **15** | **—** | **15** |
| Performance share units | **—** | **24** | **—** | **—** | **24** | **—** | **24** |
| Common stock acquired and retired | **(1)** | **(18)** | **(72)** | **—** | **(91)** | **—** | **(91)** |
| Cash dividends declared | **—** | **—** | **(287)** | **—** | **(287)** | **—** | **(287)** |
| Formation of Bakken Midstream joint venture | **—** | **763** | **—** | **—** | **763** | **1,298** | **2,061** |
| Noncontrolling interests, net | **—** | **—** | **—** | **—** | **—** | **(447)** | **(447)** |
| **Balance at December 31, 2015** | **$ 286** | **$ 4,127** | **$ 16,637** | **$ (1,664)** | **$ 19,386** | **$ 1,015** | **$ 20,401** |

See accompanying Notes to the Consolidated Financial Statements.

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

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

***Nature of Business:*** Hess Corporation 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 located in the Bakken shale play of North Dakota.

In the first quarter of 2013, we announced several initiatives to continue our transformation from an integrated energy company into a more geographically focused pure play E&P company. As part of our transformation, we 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 our Marketing and Refining (M&R) business, including our terminal, retail, energy marketing and energy trading operations, as well as the permanent shutdown of refining operations at our Port Reading 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 *Note 3, Discontinued Operations* and *Note 9, Dispositions* for additional disclosures related to the divestitures and *Note 19, Guarantees, Contingencies and Commitments* and *Note 23, Subsequent Events* for additional information related to HOVENSA.

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

In November 2015, the Financial Accounting Standards Board (FASB) issued ASU 2015-17, *Balance Sheet Classification of Deferred Taxes*, which requires deferred tax liabilities and assets be classified as noncurrent in a *Statement of Financial Position* beginning in the first quarter of 2017. As permitted by the ASU, we have adopted the update as of December 31, 2015 and recast the consolidated balance sheet at December 31, 2014. Following the establishment of the Bakken Midstream operating segment in 2015, *Note 20, Segment Information* has been recast, as has certain other information, to conform to the current period presentation.

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

***Revenue Recognition:*** The E&P segment recognizes revenue from the sale of crude oil, natural gas liquids, and natural gas, when title passes to the customer. Differences between E&P natural gas volumes sold and our entitlement share of natural gas production are not material.

In our E&P activities, we engage in crude oil purchase and sale transactions with the same counterparty that are entered into in contemplation of one another for the primary purpose of changing location or quality. These arrangements are reported net in Sales and other operating revenues in the *Statement of Consolidated Income*.

Our Bakken Midstream segment recognizes revenue from 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 when pervasive evidence of an arrangement exists, delivery has occurred or services rendered, price is fixed or determinable, and collectability is reasonably assured. Prior to 2014, when providing natural gas processing services, our Bakken Midstream operating segment purchased unprocessed natural gas from us and third parties and provided processing services pursuant to contracts whereby it retained a portion of the sales proceeds received and charged certain fees to customers. The remaining proceeds were remitted back to customers based on the contractual arrangements.

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

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

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

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

***Impairment of Long-lived Assets:*** We review long-lived assets, including oil and gas fields, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts of the long-lived assets are not expected to be recovered by estimated undiscounted future net cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is determined based on the estimated fair value of the assets generally determined by discounting anticipated future net cash flows, an income valuation approach, or by a market-based valuation approach, which are Level 3 fair value measurements. In the case of oil and gas fields, the present value of future net cash flows is based on management's best estimate of future prices, which is determined with reference to recent historical prices and published forward prices, applied to projected production volumes and discounted at a risk-adjusted rate. The projected production volumes represent reserves, including probable reserves, expected to be produced based on a projected amount of capital expenditures. The production volumes, prices and timing of production are consistent with internal projections and other externally reported information. Oil and gas prices used for determining asset impairments will generally differ from those used in the standardized measure of discounted future net cash flows, since the standardized measure requires the use of historical twelve month average prices. As a result of the prevailing low crude oil price environment, we tested our oil and gas properties for impairment at December 31, 2015. See *Note 10, Impairment*.

***Impairment of Goodwill:*** Goodwill is tested for impairment annually on October 1st or when events or circumstances indicate that the carrying amount of the goodwill may not be recoverable based on a two-step process. In step one of the impairment test, the fair value of a reporting unit is compared with its carrying amount, including goodwill. If the fair value of the reporting unit exceeds its carrying value, goodwill is not impaired. If the carrying value of the reporting unit exceeds its fair value, we perform step two to determine possible impairment by comparing the implied fair value of goodwill with the carrying amount. If the implied fair value of goodwill is less than its carrying amount, an impairment loss would be recorded. In addition to our annual test, we also performed separate goodwill impairment tests at December 31, 2015 and June 30, 2015. See *Note 10, Impairment.*

***Cash and Cash Equivalents:*** Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have maturities of three months or less when acquired.

***Inventories:*** Inventories are valued at the lower of cost or market. Cost is generally determined using average actual costs.

***Income Taxes:*** Deferred income taxes are determined using the liability method. We have net operating loss carryforwards or credit carryforwards in multiple jurisdictions and have recorded deferred tax assets for those losses and credits. Additionally, we have deferred tax assets due to temporary differences between the book basis and tax basis of certain assets and liabilities. Regular assessments are made as to the likelihood of those deferred tax assets being realized. If it is more likely than not that some or all of the deferred tax assets will not be realized, a valuation allowance is recorded to reduce the deferred tax assets to the amount that is expected to be realized. In evaluating the realizability of deferred tax assets, we consider the reversal of temporary differences, the expected utilization of net operating losses and credit carryforwards during available carryforward periods, the availability of tax planning strategies, the existence of appreciated assets and estimates of future taxable income and other factors. In addition, we recognize the financial statement effect of a tax position only when management believes that it is more likely than not, that based on the technical merits, the position will be sustained upon examination. We do not provide for deferred U.S. income taxes for that portion of undistributed earnings of foreign subsidiaries that are indefinitely reinvested in foreign operations. We classify interest and penalties associated with uncertain tax positions as income tax expense.

***Asset Retirement Obligations:*** We have material legal obligations to remove and dismantle long-lived assets and to restore land or the seabed at certain exploration and production locations. We initially recognize a liability for the fair value of legally required asset retirement obligations in the period in which the retirement obligations are incurred, and capitalize the associated asset retirement costs as part of the carrying amount of the long-lived assets. In subsequent periods, the liability is accreted, and the asset is depreciated over the useful life of the related asset. Fair value is determined by applying a credit adjusted risk-free rate to the undiscounted expected future abandonment expenditures, which represent Level 3 inputs in the fair value hierarchy defined under *Fair Value Measurements* below.

***Retirement Plans:*** We recognize the funded status of defined benefit postretirement plans in the *Consolidated Balance Sheet*. The funded status is measured as the difference between the fair value of plan assets and the projected benefit obligation. We recognize the net changes in the funded status of these plans in the year in which such changes occur. Prior service costs and actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the market value of assets are amortized over the average remaining service period of active employees.

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

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

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

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

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

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

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

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

***Share-based Compensation:*** We account for share-based compensation under the fair value method of accounting. The fair value of all share-based compensation is recognized as expense on a straight-line basis over the full vesting period of the awards. We estimate the fair value of employee stock options at the date of grant using a Black-Scholes valuation model, performance share units using a Monte Carlo simulation model, and restricted stock based on the market value of the underlying shares at the date of grant.

***Foreign Currency Translation:*** The U.S. Dollar is the functional currency (primary currency in which business is conducted) for most foreign operations. Adjustments resulting from remeasuring monetary assets and liabilities that are denominated in a currency other than the functional currency are recorded in Other, net in the *Statement of Consolidated Income*. For operations that do not use the U.S. Dollar as the functional currency, primarily those in Norway where the Norwegian Krone is used, adjustments resulting from translating foreign currency assets and liabilities into U.S. Dollars are recorded in the *Consolidated Balance Sheet* in a separate component of equity titled Accumulated other comprehensive income (loss).

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

***Environmental Expenditures:*** We accrue and expense the undiscounted environmental costs necessary to remediate existing conditions related to past operations when the future costs are probable and reasonably estimable. At year-end 2015, our reserve for estimated remediation liabilities was approximately $80 million and was included within accrued liabilities. Environmental expenditures that increase the life or efficiency of property or reduce or prevent future adverse impacts to the environment are capitalized.

***New Accounting Pronouncements:*** In May 2014, the FASB issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers*, as a new Accounting Standards Codification (ASC) Topic ASC 606. This ASU is effective for us beginning in the first quarter of 2018, with early adoption permitted from the first quarter of 2017. We are currently assessing the impact of the ASU on our consolidated financial statements.

In November 2015, the FASB issued ASU 2015-17, *Balance Sheet Classification of Deferred Taxes*, which requires deferred tax liabilities and assets be classified as noncurrent in a Balance Sheet. As permitted by the standard, we adopted the changes prior to the effective date. The retrospective application to the December 31, 2014 *Consolidated Balance Sheet* increased Deferred income taxes (long-term assets) by $202 million, decreased Deferred income taxes (long-term liabilities) by $171 million, and decreased Other current assets by $373 million.

**2. Bakken Midstream Joint Venture**

On July 1, 2015 we sold a 50% interest in Hess Infrastructure Partners LP (HIP) to Global Infrastructure Partners (GIP) for net cash consideration of approximately $2.6 billion. HIP and its affiliates primarily comprise our 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 located in the Bakken shale play 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 and 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.

The tariff agreements between our E&P operating segment and the Bakken Midstream entities became effective on January 1, 2014 and are 10-year, fee-based commercial agreements, with HIP having the sole option to renew the agreements for an additional 10-year term. These agreements include minimum volume commitments based on dedicated production, inflation escalators and fee recalculation mechanisms. The Bakken Midstream segment has minimal direct commodity price exposure, and the E&P segment retains ownership of the crude oil, natural gas or natural gas liquids processed, terminaled, stored or transported by the Bakken Midstream segment.

We consolidate the activities of HIP, which qualifies as a variable interest entity (VIE) under U.S. generally accepted accounting principles. We have concluded that we are the primary beneficiary of the VIE, as defined in the accounting standards, since we have the power, through our 50% ownership, to direct those activities that most significantly impact the economic performance of HIP. This conclusion was based on a qualitative analysis that considered HIP's governance structure, the commercial agreements between HIP and us, and the voting rights established between the members which provide us the ability to control the operations of HIP.

As a result of the sale to GIP, we recorded an after-tax gain of $763 million in additional paid-in-capital and $1,298 million in noncontrolling interest representing GIP's proportional share of our basis in the net assets of HIP. The results attributable to GIP's 50% ownership are reported within Net income (loss) attributable to noncontrolling interests in the *Statement of Consolidated Income*, while the carrying amount of GIP's equity is included as Noncontrolling interests in the *Consolidated Balance Sheet*.

Upon formation, the joint venture incurred $600 million of debt through a 5-year Term Loan A facility with the proceeds distributed equally to the partners. See *Note 8, Debt*. At December 31, 2015, HIP liabilities totaling $831 million are on a nonrecourse basis to Hess Corporation, while HIP assets available to settle the obligations of HIP included Cash and cash equivalents totaling $3 million and Property, plant and equipment totaling $2,358 million.

**3. Discontinued Operations**

The results of operations for our divested Marketing and Refining businesses included ownership of the energy trading partnership through February 2015, retail marketing through September 2014, terminals through December 2013, energy marketing through November 2013 and Port Reading refining activities through the date they were permanently shut down in February 2013, and have been reported as discontinued operations in the *Statement of Consolidated Income* for all periods presented.

Sales and other operating revenues and Income from discontinued operations were as follows:

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In millions) | |
| Sales and other operating revenues | **$ 14** | $ 9,576 | $ 22,652 |
| | | | |
| Income (loss) from discontinued operations before income taxes | **$ (74)** | $ 1,071 | $ 1,835 |
| Current tax provision (benefit) | **—** | — | — |
| Deferred tax provision (benefit) | **(26)** | 389 | 649 |
| Provision (benefit) for income taxes | **(26)** | 389 | 649 |
| Income (loss) from discontinued operations, net of income taxes | **$ (48)** | $ 682 | $ 1,186 |
| Less: Net income (loss) attributable to noncontrolling interests | **—** | 57 | (6) |
| Income (loss) from discontinued operations attributable to Hess Corporation | **$ (48)** | $ 625 | $ 1,192 |

*2015:* In February 2015, we sold our interest in HETCO, which was subsequently renamed Hartree Partners, LP (Hartree). Pursuant to the terms of the sale, Hartree was permitted to utilize our guarantees issued in favor of Hartree's existing counterparties until November 12, 2015, provided that new trades were for a period of one year or less, complied with certain credit requirements, and net exposures remained within value at risk limits previously applied by us. The guarantees remain in effect until the qualifying trades outstanding at November 12, 2015 mature. We have the right to seek reimbursement from Hartree and a separate Hartree credit support facility upon any counterparty draw on the applicable guarantee from us. No draws on the guaranteed trades have occurred through December 31, 2015. A liability of $10 million associated with the guarantee is included in Other accrued liabilities at December 31, 2015. At December 31, 2014, HETCO assets totaling $1,035 million, consisting of accounts receivable and other long-lived assets, were reported in Other current assets, and liabilities totaling $797 million, which consisted primarily of accounts payable, were reported in Accrued Liabilities in the *Consolidated Balance Sheet*.

*2014:* In September, we completed the sale of our retail business for cash proceeds of approximately $2.8 billion. This transaction resulted in a pre-tax gain of $954 million ($602 million after income taxes) after deducting the net book value of assets, including $115 million of goodwill. During the year, we recorded pre-tax gains of $275 million ($171 million after income taxes) relating to the liquidation of last-in, first-out (LIFO) inventories associated with the divested downstream operations. In addition, we recorded pre-tax charges totaling $308 million ($202 million after income taxes) for impairments, environmental matters, severance and exit related activities associated with the divestiture of downstream operations. We also recognized a pre-tax charge of $115 million ($72 million after income taxes) related to the termination of lease contracts and the purchase of 180 retail gasoline stations in preparation for the sale of the retail operations. In January, our retail business acquired our partners' 56% interest in WilcoHess, a retail gasoline joint venture, for approximately $290 million and the settlement of liabilities. In connection with this business combination, we recorded a pre-tax gain of $39 million ($24 million after income taxes) to remeasure the carrying value of our original 44% equity interest in WilcoHess to fair value, including recognition of goodwill in the amount of $115 million. The assets and liabilities acquired from WilcoHess were included in the sale of the retail business in September 2014.

*2013:* In December, we sold our U.S. East Coast terminal network, St. Lucia terminal and related businesses for cash proceeds of approximately $1.0 billion. The transaction resulted in a pre-tax gain of $739 million ($531 million after income taxes). In November, we sold our energy marketing business for cash proceeds of approximately $1.2 billion, which resulted in a pre-tax gain of $761 million ($464 million after income taxes). During the year we recognized pre-tax gains of $678 million ($414 million after income taxes) relating to the liquidation of LIFO inventories. In addition, we recorded pre-tax charges totaling $523 million ($334 million after income taxes) for impairments, severance, Port Reading refinery shutdown costs, environmental matters, and exit related activities associated with the divestiture of downstream operations.

## 4. Inventories

Inventories at December 31 were as follows:

| | 2015 | 2014 |
|---|---|---|
| | (In millions) | |
| Crude oil and natural gas liquids | **$ 144** | $ 246 |
| Materials and supplies | **255** | 281 |
| Total inventories | **$ 399** | $ 527 |

## 5. Property, Plant and Equipment

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

| | 2015 | 2014 |
|---|---|---|
| | (In millions) | |
| Exploration and Production | | |
| Unproved properties | **$ 958** | $ 1,468 |
| Proved properties | **4,202** | 4,211 |
| Wells, equipment and related facilities | **38,738** | 38,263 |
| | **43,898** | 43,942 |
| Bakken Midstream | **2,757** | 2,386 |
| Corporate, Interest and Other | **171** | 194 |
| Total — at cost | **46,826** | 46,522 |
| Less: Reserves for depreciation, depletion, amortization and lease impairment | **20,474** | 19,005 |
| Property, plant and equipment — net | **$ 26,352** | $ 27,517 |

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

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In millions) | |
| Balance at January 1 | **$ 1,416** | $ 2,045 | $ 2,259 |
| Additions to capitalized exploratory well costs pending the determination of proved reserves | **424** | 292 | 237 |
| Reclassifications to wells, facilities and equipment based on the determination of proved reserves | **(72)** | (629) | (106) |
| Capitalized exploratory well costs charged to expense | **(356)** | (235) | (267) |
| Dispositions and other | **3** | (57) | (78) |
| Ending balance at December 31 | **$ 1,415** | $ 1,416 | $ 2,045 |
| Number of wells at end of year | **35** | 37 | 50 |

In 2015, exploratory drilling activity primarily related to the Gulf of Mexico and the offshore Stabroek license in Guyana. For the years ended December 31, 2015, 2014 and 2013, reclassifications to wells, facilities and equipment based on the determination of proved reserves primarily related to Equatorial Guinea, the Stampede project in the Gulf of Mexico, (which the co-owners sanctioned for development in 2014) and the Shenzi project in the Gulf of Mexico, respectively. In 2015, capitalized exploratory well costs charged to expense related to the Dinarta Block in the Kurdistan Region of Iraq resulting from our and our partners' decision to cease further drilling and relinquish the block, gas discoveries offshore Ghana that have not sufficiently progressed appraisal negotiations with the regulator, and three wells with discovered resources offshore Australia that we determined will not be included in the current development concept for the Equus project. In 2014 capitalized well costs charged to expense included a previously capitalized exploration well in Green Canyon Block 469 in the Gulf of Mexico where it was determined no further development activities were planned, and in 2013, two previously capitalized exploration wells in Area 54, offshore Libya, were expensed due to civil unrest in the country. The preceding table excludes exploratory dry hole costs of $54 million (2014: $66 million; 2013: $77 million), which were incurred and subsequently expensed in the same year.

Exploratory well costs capitalized for greater than one year following completion of drilling were $1,053 million at December 31, 2015, separated by year of completion as follows (in millions):

| | |
|---|---|
| 2014 | $ 79 |
| 2013 | 43 |
| 2012 | 336 |
| 2011 | 207 |
| 2010 and prior | 388 |
| | $ 1,053 |

Approximately 75% of the capitalized well costs in excess of one year relates to Block WA-390-P, offshore Western Australia, where development planning and commercial activities for our natural gas discoveries are ongoing. In December 2014, we executed a non-binding letter of intent with the North West Shelf (NWS), a third-party joint venture with existing natural gas processing and liquefaction facilities. In 2015, we initiated joint front-end engineering studies with NWS and we also commenced discussions with potential long-term purchasers of liquefied natural gas. In addition, at our adjacent WA-

474-P Block which could become part of the Equus project, we plan to drill a commitment well in 2016. Successful execution of binding agreements with NWS is necessary before we can execute a gas sales agreement and sanction development of the project.

Approximately 25% of the capitalized well costs in excess of one year relates to offshore Ghana. Appraisal plans for the seven discoveries on the block were submitted to the Ghanaian government in May 2013 for approval. Five of the plans were approved and discussions continue with the government on the two remaining appraisal plans. In 2014, we completed three appraisal wells and subsurface evaluation, and development planning progressed 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.

## 6. Goodwill

The changes in the carrying amount of goodwill were as follows:

| | Exploration and Production | Bakken Midstream | Total |
|---|---|---|---|
| | | (In millions) | |
| Beginning balance at January 1, 2014 | $ 1,869 | $ — | $ 1,869 |
| Acquisitions | 115 | — | 115 |
| Dispositions | (126) | — | (126) |
| Balance at December 31, 2014 | 1,858 | — | 1,858 |
| Reclassification | **(375)** | **375** | **—** |
| Impairment | **(1,483)** | **—** | **(1,483)** |
| Ending balance at December 31, 2015 | **$ —** | **$ 375** | **$ 375** |

In the second quarter of 2015, we established a new operating segment, the Bakken Midstream segment which had previously been reported as part of the Onshore reporting unit within the E&P operating segment. The E&P operating segment previously had two reporting units, Offshore which had allocated goodwill of $1,098 million and Onshore which had allocated goodwill of $760 million prior to forming the Bakken Midstream operating segment. Upon formation of the Bakken Midstream operating segment, we allocated $375 million of goodwill from the Onshore reporting unit to the Bakken Midstream operating segment based on the relative fair values of the Bakken Midstream business and the remainder of the Onshore reporting unit. There was no change to the composition of the Offshore reporting unit. See *Note 10, Impairment* for further information.

The acquired goodwill in 2014 resulted from the purchase of our partners' 56% interest in WilcoHess, which was subsequently disposed of as part of the sale of our retail marketing operations. See *Note 3, Discontinued Operations* for further information.

## 7. Asset Retirement Obligations

The following table describes changes to our asset retirement obligations:

| | 2015 | 2014 |
|---|---|---|
| | (In millions) | |
| Asset retirement obligations at beginning of period | **$ 2,723** | $ 2,772 |
| Liabilities incurred | **57** | 63 |
| Liabilities settled or disposed of | **(360)** | (420) |
| Accretion expense | **126** | 136 |
| Revisions of estimated liabilities | **92** | 263 |
| Foreign currency translation | **(255)** | (91) |
| Asset retirement obligations at end of period | **2,383** | 2,723 |
| Less: Current obligations | **225** | 442 |
| Long-term obligations at end of period | **$ 2,158** | $ 2,281 |

The liabilities settled or disposed of related primarily to abandonment activities conducted at the Valhall field offshore Norway and at formerly operated fields in the U.K. North Sea. The revisions in 2015 and 2014 primarily reflect changes in the expected scope of operations and updates to service and equipment costs.

## 8. Debt

Long-term debt at December 31 consisted of the following:

| | 2015 | 2014 |
|---|---|---|
| | (In millions) | |
| **Debt excluding Bakken Midstream:** | | |
| Fixed-rate public notes: | | |
| 1.3% due 2017 | **$ 300** | $ 300 |
| 8.1% due 2019 | **999** | 999 |
| 3.5% due 2024 | **298** | 298 |
| 7.9% due 2029 | **696** | 696 |
| 7.3% due 2031 | **747** | 747 |
| 7.1% due 2033 | **598** | 598 |
| 6.0% due 2040 | **745** | 745 |
| 5.6% due 2041 | **1,242** | 1,242 |
| Total fixed-rate public notes | **5,625** | 5,625 |
| Financing obligations associated with floating production system | **264** | 331 |
| Fair value adjustments - interest rate hedging | **31** | 31 |
| Total debt excluding Bakken Midstream | **$ 5,920** | $ 5,987 |
| **Debt related to Bakken Midstream:** | | |
| Bakken Midstream - term loan A facility | **$ 600** | $ — |
| Bakken Midstream - revolving credit facility | **110** | — |
| Total debt related to Bakken Midstream | **$ 710** | $ — |
| **Total long-term debt:** | | |
| Total debt (a) (b) | **$ 6,630** | $ 5,987 |
| Less: Current maturities of long-term debt | **86** | 68 |
| Total long-term debt | **$ 6,544** | $ 5,919 |

*(a) At December 31, 2015 the fair value of total debt amounted to $6,515 million (2014: $7,003 million).*
*(b) The aggregate long-term debt maturing during the next five years is as follows (in millions): 2016—$86; 2017—$412; 2018—$123; 2019—$1,121 and 2020—$560.*

In January 2015, we entered into a new $4 billion syndicated revolving credit facility that expires in January 2020. The new facility, which replaced a $4 billion facility that was scheduled to expire in April 2016, can be used for borrowings and letters of credit. Based on our credit rating as of December 31, 2015, borrowing on the facility will generally bear interest at 1.075% above the London Interbank Offered Rate (LIBOR) with the facility fee amounting to 0.175% per annum. The interest rate and facility fee are subject to adjustment if our credit rating changes. At December 31, 2015, there were no borrowings outstanding or letters of credit issued against the syndicated revolving credit facility. In June 2014, we issued $600 million of unsecured, fixed-rate notes ($598 million net of discount) comprising $300 million with a coupon of 1.3% and scheduled to mature in June 2017 as well as $300 million with a coupon of 3.5% and scheduled to mature in July 2024. In 2014, we repaid $590 million of debt, including $250 million of unsecured, fixed-rate notes, $249 million for the payment of various lease obligations primarily to retire retail gasoline station leases and $74 million assumed in the acquisition of WilcoHess. In 2015 we capitalized $45 million of interest (2014: $76 million; 2013: $60 million).

At December 31, 2015, and 2014, our fixed-rate public notes had a principal amount of $5,650 million ($5,625 million net of unamortized discount) with a weighted average interest rate 6.4%. Our long-term debt agreements, including the revolving credit facility, contain financial covenants that restrict the amount of total borrowings and secured debt. The most restrictive of these covenants allow us to borrow up to an additional $5,495 million of secured debt at December 31, 2015.

In July 2015, HIP, a 50/50 joint venture between us and GIP, incurred $600 million of debt through a 5-year Term Loan A facility. The proceeds from the debt were distributed equally to the partners. HIP also entered into a $400 million 5-year syndicated revolving credit facility, which can be used for borrowings and letters of credit, and is expected to fund the joint venture's operating activities and capital expenditures. Borrowings on both loan facilities generally bear interest at LIBOR plus an applicable margin ranging from 1.10% to 2.00%. Facility fees on the revolving credit facility accrue at an applicable rate every quarter, ranging from 0.15% to 0.35% per annum. Prior to obtaining credit ratings, applicable interest margins and facility fees are based on the joint venture's leverage ratio, which is calculated as total debt to Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA). If the joint venture obtains credit ratings, pricing levels will be based on its credit ratings in effect from time to time. The joint venture is subject to customary covenants in the credit agreement, including financial covenants that generally require a leverage ratio of no more than 5.0 to 1.0 for the prior four fiscal quarters and an interest coverage ratio, which is calculated as EBITDA to interest expense, of no less than 2.25 to 1.0 for the prior four fiscal quarters. At December 31, 2015, borrowings attributable to the joint venture, which are non-recourse to Hess Corporation, amounted to $600 million on the Term Loan A loan facility and $110 million on the revolving credit facility. HIP is in compliance with all debt covenants at December 31, 2015, and its financial covenants do not currently impact their ability to issue indebtedness to fund future capital expenditures.

Outstanding letters of credit at December 31 were as follows:

| | 2015 | 2014 |
|---|---|---|
| | (In millions) | |
| Committed lines (a) | **$ 10** | $ 25 |
| Uncommitted lines (a) | **103** | 372 |
| Total (b) | **$ 113** | $ 397 |

*(a) At December 31, 2015, committed and uncommitted lines have expiration dates through 2016.*
*(b) At December 31, 2015, $32 million relates to contingent liabilities and $81 million relates to liabilities recorded in the Consolidated Balance Sheet (2014: $54 million and $343 million, respectively).*

## 9. Dispositions

*2015:* In December, we completed the disposition of our interest in Algeria and recognized a pre-tax loss of $21 million ($21 million after income taxes), and sold land associated with our former joint venture interest in the Bayonne Energy Center for $20 million, resulting in a pre-tax gain of $20 million ($13 million after income taxes). In the third quarter of 2015, we completed the sale of approximately 13,000 acres of Utica dry gas acreage for a sale price of approximately $120 million. This transaction resulted in a pre-tax gain of $49 million ($31 million after income taxes).

*2014:* In January, we completed the sale of our interest in the Pangkah asset, offshore Indonesia for cash proceeds of approximately $650 million, which resulted in a pre-tax gain of $31 million ($10 million loss after income taxes). In April, we completed the sale of our interests in Thailand for cash proceeds of approximately $805 million, which resulted in a pre-tax gain of $706 million ($706 million after income taxes). In the first six months of 2014, we completed the sale of approximately 77,000 net acres in the dry gas area of the Utica shale play including related wells and facilities through multiple transactions, for cash proceeds of $1,075 million and recorded a pre-tax gain of $62 million ($35 million gain after income taxes). In June, we completed the sale of our joint venture interest in an electric generating facility in Newark, New Jersey for cash proceeds of $320 million, resulting in a pre-tax gain of approximately $13 million ($8 million after income taxes). In September, we sold our joint venture interest in Bayonne Energy Center for $79 million, which did not result in a gain or loss. Also in September, we completed the sale of our interest in an exploration asset in the United Kingdom North Sea for $53 million, which resulted in a pre-tax gain of $33 million ($33 million after income taxes).

*2013:* In January, we completed the sale of our interests in the Beryl fields and the Scottish Area Gas Evacuation System in the UK North Sea for cash proceeds of $442 million; this transaction resulted in a pre-tax gain of $328 million ($323 million after income taxes). In March, we sold our interests in the Azeri-Chirag-Guneshli fields, offshore Azerbaijan in the Caspian Sea, and the associated Baku-Tbilisi-Ceyhan (BTC) oil transportation pipeline company for cash proceeds of $884 million; this transaction resulted in a pre-tax gain of $360 million ($360 million after income taxes). In April, we completed the sale of our Russian subsidiary, Samara-Nafta, for cash proceeds of $2.1 billion; based on our 90% interest in Samara-Nafta, after-tax proceeds to Hess were approximately $1.9 billion. This transaction resulted in a pre-tax gain of $1,119 million ($1,119 million after income taxes), which was reduced by $168 million for the noncontrolling interest holder's share of the gain, resulting in a net gain attributable to us of $951 million. In December, we completed the sale of our interest in the Natuna A Field, offshore Indonesia for total cash proceeds of approximately $656 million; this transaction resulted in a pre-tax gain of $388 million ($343 million after income taxes).

**10. Impairment**

In 2015, we recorded pre-tax goodwill impairment charges totaling $1,483 million ($1,483 million after income taxes). As a result of establishing the Bakken Midstream operating segment in the second quarter of 2015, (see *Note 6, Goodwill*), we performed impairment tests on the Offshore and Onshore reporting units prior to creation of the Bakken Midstream segment in accordance with accounting standards for goodwill. No impairment resulted from this assessment. In addition, we performed separate impairment tests at June 30, 2015, on the allocated goodwill to the Bakken Midstream segment and Onshore reporting unit of the E&P segment following the creation of the Bakken Midstream segment. No impairment existed for the Bakken Midstream segment, but goodwill allocated to the Onshore reporting unit of $385 million did not pass the impairment test, and as a result was reduced to its implied fair value of zero based on a hypothetical purchase price allocation as stipulated in the accounting standards. In addition, as part of the further deterioration in crude oil prices in the fourth quarter of 2015, we determined goodwill allocated to the Offshore reporting unit of $1,098 million did not pass the impairment test, and as a result was reduced to its implied fair value of zero based on a hypothetical purchase price allocation as stipulated in the accounting standards. Fair value of our Onshore and Offshore reporting units were determined using multiple valuation techniques, including projected discounted cash flows of producing assets and known development projects. The determination of projected discounted cash flows depends on estimates about oil and gas reserves, future prices, operating costs, capital expenditures, discount rate and timing of future net cash flows. We also considered the relative market valuation of similar peer companies using market multiples, and other observable market data, in assessing fair value of each reporting unit. The valuation methodologies used represent Level 3 measurements as defined by accounting standards.

As a result of declining commodity prices, in 2015 we also recognized an impairment charge of $133 million pre-tax ($83 million after income taxes) relating to our conventional legacy assets in North Dakota based projected discounted cash flows, using similar Level 3 inputs to those discussed above.

In 2013, we announced the sale of our E&P assets in Indonesia for approximately $1.3 billion. The sale was executed in two separate transactions, with Natuna A completing in December 2013 and Pangkah in January 2014, as a result of a partner exercising their preemptive rights. Based on the sales proceeds for each transaction, results of operations for 2013 included a pre-tax gain on sale related to Natuna A of $388 million ($343 million after income taxes), and a pre-tax asset impairment charge of $289 million ($187 million after income taxes) to adjust the carrying value of the Pangkah assets to their fair value at December 31, 2013.

**11. Share-based Compensation**

We have established and maintain a Long-term Incentive Plan (LTIP), as amended, for the granting of restricted common shares, performance share units (PSUs) and stock options to our employees. As of December 31, 2015, the total number of authorized common stock under LTIP, as amended, was 38.0 million shares, of which we have 14.2 million shares available for issuance. Outstanding restricted stock and PSUs generally vest three years from the date of grant. Restricted common shares are valued based on the prevailing market price of our common stock on the date of grant. Outstanding stock options vest over three years from the date of grant and have a 10-year term and an exercise price equal to the market price on the date of grant.

The number of shares of common stock to be issued under the PSU agreement is based on a comparison of the Corporation's total shareholder return (TSR) to the TSR of a predetermined group of peer companies over a three-year performance period ending December 31 of the year prior to settlement of the grant. Payouts of the performance share awards will range from 0% to 200% of the target awards based on the Corporation's TSR ranking within the peer group.

Dividend equivalents for the performance period will accrue on performance shares, but will only be paid out on earned shares after the performance period.

Share-based compensation expense consisted of the following:

| | Before Income Taxes | | | After Income Taxes | | |
|---|---|---|---|---|---|---|
| | **2015** | 2014 | 2013 (b) | **2015** | 2014 | 2013 |
| | (In millions) | | | | | |
| Restricted stock | **$ 67** | $ 62 | $ 31 | **$ 42** | $ 39 | $ 19 |
| Stock options | **5** | 2 | 13 | **3** | 1 | 8 |
| Performance share units | **25** | 19 | 10 | **16** | 12 | 6 |
| Total (a) | **$ 97** | $ 83 | $ 54 | **$ 61** | $ 52 | $ 33 |

*(a) Includes pre-tax share-based compensation expense included in Income from continuing operations of approximately $97 million, $87 million and $60 million for 2015, 2014 and 2013, respectively.*
*(b) Reflects the reversal of $33 million ($25 million for restricted stock, $7 million for PSUs and $1 million for stock options) in compensation expense for grants that were not expected to vest as a result of our transformation to a pure play E&P company.*

Based on share-based compensation awards outstanding at December 31, 2015, unearned compensation expense, before income taxes, will be recognized in future years as follows (in millions): 2016—$73, 2017—$42 and 2018—$6.

Share-based compensation activity consisted of the following:

| | Performance Share Units | | Stock Options | | Restricted Stock | |
|---|---|---|---|---|---|---|
| | Performance Share Units | Weighted - Average Fair Value on Date of Grant | Options | Weighted - Average Exercise Price per Share | Shares of Restricted Common Stock | Weighted - Average Price on Date of Grant |
| | (In thousands, except per share amounts) | | | | | |
| Outstanding at January 1, 2015 | 800 | $ 89.91 | 6,766 | $ 66.79 | 2,901 | $ 71.58 |
| Granted | 366 | 76.64 | 521 | 74.49 | 1,131 | 74.38 |
| Exercised | — | — | (244) | 48.51 | — | — |
| Vested | (288) | 72.93 | — | — | (921) | 63.63 |
| Forfeited | (58) | 97.16 | (132) | 79.29 | (291) | 71.39 |
| Outstanding at December 31, 2015 | 820 | $ 89.43 | 6,911 | $ 67.77 | 2,820 | $ 75.32 |

As of December 31, 2015, there were 6.91 million outstanding stock options (6.31 million exercisable) with a weighted average remaining contractual life of 3.5 years (3.0 years for exercisable options). The weighted average exercise price for options exercisable at December 31, 2015 was $67.03 per share.

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

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Risk free interest rate | **1.77%** | 1.86% | — |
| Stock price volatility | **0.312** | 0.363 | — |
| Dividend yield | **1.34%** | 1.24% | — |
| Expected life in years | **6.0** | 6.0 | — |
| Weighted average fair value per option granted | **$ 21.00** | $ 26.46 | — |

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

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Risk free interest rate | **1.02%** | 0.65% | 0.36% |
| Stock price volatility | **0.270** | 0.359 | 0.359 |
| Contractual term in years | **3.0** | 3.0 | 3.0 |
| Grant date price of Hess common stock | **$ 74.49** | $ 80.35 | $ 69.49 |

The risk free interest rate is based on the vesting period of the award and is obtained from published sources. The stock price volatility is determined from the historical stock prices of the peer group using the vesting period. The contractual term is equivalent to the vesting period.

## 12. Retirement Plans

We have funded noncontributory defined benefit pension plans for a significant portion of our employees. In addition, we have an unfunded supplemental pension plan covering certain employees, which provides incremental payments that would have been payable from our principal pension plans, were it not for limitations imposed by income tax regulations.

The plans provide defined benefits based on years of service and final average salary. Additionally, we maintain an unfunded postretirement medical plan that provides health benefits to certain qualified retirees from ages 55 through 65. The measurement date for all retirement plans is December 31.

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

| | Funded Pension Plans | | Unfunded Pension Plan | | Postretirement Medical Plan | |
|---|---|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 | 2015 | 2014 |
| | (In millions) | | | | | |
| **Change in benefit obligation** | | | | | | |
| Balance at January 1 | **$ 2,450** | $ 1,957 | **$ 278** | $ 253 | **$ 94** | $ 97 |
| Service cost | **51** | 45 | **16** | 12 | **4** | 4 |
| Interest cost | **93** | 91 | **9** | 9 | **3** | 3 |
| Actuarial (gain) loss (a) | **(156)** | 470 | **(2)** | 61 | **5** | (4) |
| Benefit payments (b) | **(85)** | (77) | **(42)** | (57) | **(8)** | (6) |
| Plan curtailments | **(4)** | (3) | **—** | — | **—** | — |
| Special termination benefits | **1** | 2 | **—** | — | **—** | — |
| Foreign currency exchange rate changes | **(29)** | (35) | **—** | — | **—** | — |
| Balance at December 31 | **2,321** | 2,450 | **259** | 278 | **98** | 94 |
| **Change in fair value of plan assets** | | | | | | |
| Balance at January 1 | **$ 2,251** | $ 2,145 | **$ —** | $ — | **$ —** | $ — |
| Actual return on plan assets | **28** | 151 | **—** | — | **—** | — |
| Employer contributions | **44** | 68 | **42** | 57 | **8** | 6 |
| Benefit payments (b) | **(85)** | (77) | **(42)** | (57) | **(8)** | (6) |
| Foreign currency exchange rate changes | **(32)** | (36) | **—** | — | **—** | — |
| Balance at December 31 | **2,206** | 2,251 | **—** | — | **—** | — |
| **Funded status (plan assets greater (less) than benefit obligations) at December 31** | **$ (115)** | $ (199) | **$ (259)** | $ (278) | **$ (98)** | $ (94) |
| **Unrecognized net actuarial (gains) losses** | **775** | 859 | **105** | 135 | **—** | (5) |

*(a) The change in discount rate and mortality assumptions in 2014 resulted in total actuarial losses of approximately $330 million and $125 million, respectively.*
*(b) Benefit payments include lump-sum settlement payments of $41 million in 2015 and $55 million in 2014.*

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

| | Funded Pension Plans | | Unfunded Pension Plan | | Postretirement Medical Plan | |
|---|---|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 | 2015 | 2014 |
| | (In millions) | | | | | |
| Pension asset / (accrued benefit liability) | **$ (115)** | $ (199) | **$ (259)** | $ (278) | **$ (98)** | $ (94) |
| Accumulated other comprehensive loss, pre-tax (a) | **775** | 859 | **105** | 135 | **—** | (5) |

(a) *The after-tax deficit reflected in Accumulated other comprehensive income (loss) was $563 million at December 31, 2015 (2014: $652 million).*

At December 31, 2015, the accumulated benefit obligation for the funded and unfunded defined benefit pension plans was $2,223 million and $196 million, respectively (2014: $2,325 million and $214 million, respectively).

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

| | Pension Plans | | | Postretirement Medical Plan | | |
|---|---|---|---|---|---|---|
| | 2015 | 2014 | 2013 | 2015 | 2014 | 2013 |
| | (In millions) | | | | | |
| Service cost | **$ 67** | $ 57 | $ 73 | **$ 4** | $ 4 | $ 4 |
| Interest cost | **102** | 100 | 89 | **3** | 3 | 3 |
| Expected return on plan assets | **(168)** | (161) | (141) | **—** | — | — |
| Amortization of unrecognized net actuarial losses | **75** | 32 | 61 | **—** | — | 1 |
| Settlement loss | **17** | 24 | — | **—** | — | — |
| Curtailment loss | **—** | — | 1 | **—** | — | — |
| Special termination benefit recognized | **1** | 1 | 5 | **—** | — | — |
| **Net periodic benefit cost** | **$ 94** | **$ 53** | **$ 88** | **$ 7** | **$ 7** | **$ 8** |

For 2016, the pension and postretirement medical expense is estimated to be approximately $71 million, which includes approximately $64 million related to the amortization of unrecognized net actuarial losses.

The weighted average actuarial assumptions used for funded and unfunded pension plans were as follows:

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| **Weighted average assumptions used to determine benefit obligations at December 31** | | | |
| Discount rate | **4.1%** | 3.8% | 4.6% |
| Rate of compensation increase | **4.5%** | 5.0% | 4.4% |
| **Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31** | | | |
| Discount rate | **3.8%** | 4.6% | 4.0% |
| Expected return on plan assets | **7.5%** | 7.5% | 7.5% |
| Rate of compensation increase | **5.0%** | 4.4% | 4.3% |

The actuarial assumptions used for postretirement medical plan, as follows:

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| **Assumptions used to determine benefit obligations at December 31** | | | |
| Discount rate | **3.5%** | 3.1% | 3.6% |
| Initial health care trend rate | **6.7%** | 6.8% | 7.1% |
| Ultimate trend rate | **4.5%** | 4.5% | 4.6% |
| Year in which ultimate trend rate is reached | **2038** | 2029 | 2027 |

The assumptions used to determine net periodic benefit cost for each year were established at the end of each previous year while the assumptions used to determine benefit obligations were established at each year-end. The net periodic benefit cost and the actuarial present value of benefit obligations are based on actuarial assumptions that are reviewed on an annual basis. The discount rate is developed based on a portfolio of high-quality, fixed income debt instruments with maturities that approximate the expected payment of plan obligations. The overall expected return on plan assets is developed from the expected future returns for each asset category, weighted by the target allocation of pension assets to that asset category.

Our investment strategy is to maximize long-term returns at an acceptable level of risk through broad diversification of plan assets in a variety of asset classes. Asset classes and target allocations are determined by our investment committee and include domestic and foreign equities, fixed income, and other investments, including hedge funds, real estate and private equity. Investment managers are prohibited from investing in securities issued by the Corporation unless indirectly held as part of an index strategy. The majority of plan assets are highly liquid, providing ample liquidity for benefit payment requirements. The current target allocations for plan assets are 50% equity securities, 25% fixed income securities (including cash and short-term investment funds) and 25% to all other types of investments. Asset allocations are rebalanced on a periodic basis throughout the year to bring assets to within an acceptable range of target levels.

The following tables provide the fair value of the financial assets of the funded pension plans as of December 31, 2015 and 2014 in accordance with the fair value measurement hierarchy described in *Note 1, Nature of Operations, Basis of Presentation and Summary of Accounting Policies* included herewith.

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| | | (In millions) | | |
| **December 31, 2015** | | | | |
| **Cash and short-term investment funds** | $ — | **$ 34** | $ — | **$ 34** |
| **Equities:** | | | | |
| U.S. equities (domestic) | **556** | **—** | **—** | **556** |
| International equities (non-U.S.) | **159** | **266** | **—** | **425** |
| Global equities (domestic and non-U.S.) | **2** | **217** | **—** | **219** |
| **Fixed income:** | | | | |
| Treasury and government issued (a) | **—** | **213** | **—** | **213** |
| Government related (b) | **—** | **6** | **1** | **7** |
| Mortgage-backed securities (c) | **—** | **174** | **2** | **176** |
| Corporate | **—** | **157** | **—** | **157** |
| **Other:** | | | | |
| Hedge funds | **—** | **—** | **216** | **216** |
| Private equity funds | **—** | **—** | **122** | **122** |
| Real estate funds | **12** | **—** | **52** | **64** |
| Diversified commodities funds | **—** | **17** | **—** | **17** |
| | **$ 729** | **$ 1,084** | **$ 393** | **$ 2,206** |
| **December 31, 2014** | | | | |
| **Cash and short-term investment funds** | $ 6 | $ 47 | $ — | $ 53 |
| **Equities:** | | | | |
| U.S. equities (domestic) | 719 | — | — | 719 |
| International equities (non-U.S.) | 72 | 177 | — | 249 |
| Global equities (domestic and non-U.S.) | 10 | 218 | — | 228 |
| **Fixed income:** | | | | |
| Treasury and government issued (a) | — | 222 | — | 222 |
| Government related (b) | — | 7 | 1 | 8 |
| Mortgage-backed securities (c) | — | 147 | 1 | 148 |
| Corporate | 3 | 137 | — | 140 |
| **Other:** | | | | |
| Hedge funds | — | — | 302 | 302 |
| Private equity funds | — | — | 105 | 105 |
| Real estate funds | 12 | — | 48 | 60 |
| Diversified commodities funds | — | 17 | — | 17 |
| | $ 822 | $ 972 | $ 457 | $ 2,251 |

(a) *Includes securities issued and guaranteed by U.S. and non-U.S. governments.*
(b) *Primarily consists of securities issued by governmental agencies and municipalities.*
(c) *Comprised of U.S. residential and commercial mortgage-backed securities.*

Cash and short-term investment funds consist of cash on hand and short-term investment funds that provide for daily investments and redemptions and are valued and carried at a $1 net asset value (NAV) per fund share. Cash on hand is classified as Level 1 and short-term investment funds are classified as Level 2.

Equities consist of equity securities issued by U.S. and non-U.S. corporations as well as commingled investment funds that invest in equity securities. Individually held equity securities, which are traded actively on exchanges and have readily available price quotes, are classified as Level 1. Commingled fund values, which are valued at the NAV per fund share derived from the quoted prices in active markets of the underlying securities, are classified as Level 2.

Fixed income investments consist of securities issued by the U.S. government, non-U.S. governments, governmental agencies, municipalities and corporations, and agency and non-agency mortgage-backed securities. This investment category also includes commingled investment funds that invest in fixed income securities. Individual fixed income securities are generally priced on the basis of evaluated prices from independent pricing services, which are monitored and provided by the third-party custodial firm responsible for safekeeping plan assets. Individual fixed income securities are classified as Level 2 or 3. Fixed income commingled fund values, which reflect the NAV per fund share derived indirectly from observable inputs or from quoted prices in less liquid markets of the underlying securities, are classified as Level 2.

Other investments consist of exchange-traded real estate investment trust securities, as well as commingled fund and limited partnership investments in hedge funds, private equity, real estate and diversified commodities. Exchange-traded securities are classified as Level 1. Commingled fund values reflect the NAV per fund share and are classified as Level 2 or 3. Private equity and real estate limited partnership values reflect information reported by the fund managers, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data and independent appraisals from third-party sources with professional qualifications. Hedge funds, private equity and non-exchange-traded real estate investments are classified as Level 3.

The following tables provide changes in financial assets that are measured at fair value based on Level 3 inputs that are held by institutional funds classified as:

| | Fixed Income | Hedge Funds | Private Equity Funds | Real Estate Funds | Total |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| Balance at January 1, 2014 | $ 3 | $ 291 | $ 89 | $ 47 | $ 430 |
| Actual return on plan assets | — | 9 | 15 | — | 24 |
| Purchases, sales or other settlements | (1) | 2 | 1 | 1 | 3 |
| Net transfers in (out) of Level 3 | — | — | — | — | — |
| Balance at December 31, 2014 | 2 | 302 | 105 | 48 | 457 |
| Actual return on plan assets | **—** | **(5)** | **18** | **9** | **22** |
| Purchases, sales or other settlements | **1** | **(81)** | **(1)** | **(5)** | **(86)** |
| Net transfers in (out) of Level 3 | — | — | — | — | — |
| Balance at December 31, 2015 | **$ 3** | **$ 216** | **$ 122** | **$ 52** | **$ 393** |

We expect to contribute approximately $27 million to our funded pension plans in 2016.

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

| | |
|---|---|
| 2016 | $ 111 |
| 2017 | 117 |
| 2018 | 120 |
| 2019 | 129 |
| 2020 | 134 |
| Years 2021 to 2025 | 711 |

We also have several defined contribution plans for certain eligible employees. Employees may contribute a portion of their compensation to these plans and we match a portion of the employee contributions. We recorded expense of $28 million in 2015 for contributions to these plans (2014: $32 million; 2013: $41 million).

In February 2016, we assumed the HOVENSA pension plan as per the court approved settlement of the HOVENSA Liquidation Plan. See *Note 23, Subsequent Events*.

## 13. Exit and Disposal Costs

In 2015, we incurred severance expense of $13 million (2014: $76 million; 2013: $252 million) and paid accrued severance costs of $57 million (2014: $170 million; 2013: $81 million). The employee severance charges primarily resulted from our divestiture program announced in 2013. The severance charges were based on amounts incurred under ongoing severance arrangements or other statutory requirements, plus amounts earned under enhanced benefit arrangements. The expense associated with the enhanced benefits was recognized ratably over the estimated service period required for the employee to earn the benefit upon termination.

In 2015, we recorded exit related costs of $15 million (2014: $65 million; 2013: $220 million) and paid $21 million (2014: $158 million; 2013: $102 million) for accrued facility and other exit costs. The facility and other exit costs relate to charges associated with the cessation of use of certain leased office space, contract terminations, professional fees, and costs associated with the shutdown of Port Reading refining operations.

At December 31, 2015, we have accrued liabilities of $33 million (2014: $77 million) for severance and $19 million (2014: $25 million) for exit related costs. We expect to make all payments for severance in 2016, and to pay facility and exit cost through 2027.

## 14. Income Taxes

The provision (benefit) for income taxes from continuing operations consisted of:

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In millions) | |
| **United States** | | | |
| Federal | | | |
| Current | **$ (7)** | $ (1) | $ 8 |
| Deferred | **(995)** | 156 | 103 |
| State | **(61)** | 57 | 9 |
| | **(1,063)** | 212 | 120 |
| **Foreign** | | | |
| Current | **4** | 453 | 941 |
| Deferred | **(231)** | 79 | 186 |
| | **(227)** | 532 | 1,127 |
| Total | **(1,290)** | 744 | 1,247 |
| Adjustment of deferred taxes for foreign income tax law changes (a) | **(9)** | — | (682) |
| **Total provision (benefit) for income taxes** | **$ (1,299)** | $ 744 | $ 565 |

*(a) The reported amount for 2015 reflects $9 million for the effect of a change in Norway's hydrocarbon and base corporate income tax rates in December 2015. The reported amount for 2013 reflects $674 million for the effect of the Denmark hydrocarbon income tax law change to the Chapter 3A regime in December 2013 and $8 million for the effect of a change in Norway's hydrocarbon and base corporate income tax rates in December 2013.*

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

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In millions) | |
| United States (a) | **$ (2,728)** | $ 676 | $ 580 |
| Foreign | **(1,530)** | 1,760 | 4,021 |
| Total income (loss) from continuing operations before income taxes | **$ (4,258)** | $ 2,436 | $ 4,601 |

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

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

| | 2015 | 2014 |
|---|---|---|
| | (In millions) | |
| **Deferred tax liabilities** | | |
| Property, plant and equipment and investments (a) | **$ (3,743)** | $ (4,226) |
| Other | **(257)** | (269) |
| Total deferred tax liabilities | **(4,000)** | (4,495) |
| **Deferred tax assets** | | |
| Net operating loss carryforwards | **3,852** | 3,010 |
| Tax credit carryforwards | **188** | 193 |
| Property, plant and equipment and investments (a) | **981** | 1,110 |
| Accrued compensation, deferred credits and other liabilities | **492** | 449 |
| Asset retirement obligations | **1,220** | 1,421 |
| Other | **165** | 261 |
| Total deferred tax assets | **6,898** | 6,444 |
| Valuation allowances | **(1,579)** | (1,416) |
| Total deferred tax assets, net of valuation allowances | **5,319** | 5,028 |
| Net deferred tax assets | **$ 1,319** | $ 533 |

*(a) 2014 has been adjusted to conform to the 2015 presentation.*

At December 31, 2015, we have recognized a gross deferred tax asset related to net operating loss carryforwards of $3,852 million before application of valuation allowances. The deferred tax asset is comprised of $2,245 million attributable to foreign net operating losses which begin to expire in 2025, $1,394 million attributable to U.S. federal operating losses which begin to expire in 2020 and $213 million attributable to losses in various U.S. states which begin to expire in 2016. The deferred tax asset attributable to foreign net operating losses, net of valuation allowances, is $1,631 million, substantially all of which relates to loss carryforwards in Denmark, Norway and Malaysia. The deferred tax asset attributable to federal net operating losses, net of valuation allowances, is $1,394 million. The deferred tax asset attributable to state net operating losses, net of valuation allowances, is $63 million, substantially all of which relates to North Dakota. At December 31, 2015, we have federal, state and foreign alternative minimum tax credit carryforwards of $102 million which can be carried forward indefinitely, and approximately $1 million of other business credit carryforwards. The deferred tax asset attributable to these credits, net of valuation allowances is $54 million. A full valuation allowance is established against our foreign tax credit carryforwards of $85 million which begin to expire in 2016.

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

| | 2015 | 2014 |
|---|---|---|
| | (In millions) | |
| Deferred income taxes (long-term asset) | **$ 2,653** | $ 2,371 |
| Deferred income taxes (long-term liability) | **(1,334)** | (1,838) |
| Net deferred tax assets | **$ 1,319** | $ 533 |

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

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| U.S. statutory rate | **35.0 %** | 35.0 % | 35.0 % |
| Effect of foreign operations (a)(b) | **5.9** | 0.7 | 5.9 |
| State income taxes, net of Federal income tax | **0.9** | 1.5 | 0.1 |
| Change in enacted tax laws | **0.2** | — | (14.8) |
| Gains on asset sales, net | **(0.2)** | (8.3) | (15.6) |
| Goodwill impairment | **(12.2)** | — | — |
| Valuation allowance against previously benefitted deferred tax assets (a) | **(3.1)** | 0.6 | 1.0 |
| Benefit of legal entity restructuring | **3.5** | — | — |
| Other (a) | **0.5** | 1.0 | 0.7 |
| Total | **30.5 %** | 30.5 % | 12.3 % |

*(a) 2014 and 2013 have been adjusted to conform to the 2015 presentation.*
*(b) The variance in effective income tax rates attributable to the effect of foreign operations primarily resulted from the mix of income among high and low tax rate jurisdictions.*

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

| | 2015 | 2014 |
|---|---|---|
| | (In millions) | |
| Balance at January 1 | **$ 603** | $ 570 |
| Additions based on tax positions taken in the current year | **19** | 42 |
| Additions based on tax positions of prior years | **29** | 70 |
| Reductions based on tax positions of prior years | **(31)** | (76) |
| Reductions due to settlements with taxing authorities | **(12)** | (3) |
| Reductions due to lapses in statutes of limitation | **(4)** | — |
| Balance at December 31 | **$ 604** | $ 603 |

The December 31, 2015 balance of unrecognized tax benefits includes $529 million that, if recognized, would impact our effective income tax rate. Over the next 12 months, it is reasonably possible that the total amount of unrecognized tax benefits could decrease between $109 million to $161 million due to settlements with taxing authorities or other resolutions, as well as lapses in statutes of limitation. At December 31, 2015, our accrued interest and penalties related to unrecognized tax benefits is $74 million (2014: $62 million).

We have not recognized deferred income taxes on the portion of undistributed earnings of foreign subsidiaries expected to be indefinitely reinvested in foreign operations. At December 31, 2015, we have undistributed earnings from foreign subsidiaries, which we expect to be indefinitely reinvested in foreign operations, of approximately $7.7 billion. We have not measured the unrecognized deferred tax liability related to these earnings because this determination is not practicable.

We file income tax returns in the U.S. and various foreign jurisdictions. We are no longer subject to examinations by income tax authorities in most jurisdictions for years prior to 2005.

## 15. Outstanding and Weighted Average Common Shares

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

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In millions) | |
| Balance at January 1 | **285.8** | 325.3 | 341.5 |
| Activity related to restricted common stock awards, net | **0.8** | 0.6 | 0.8 |
| Stock options exercised | **0.2** | 3.3 | 2.3 |
| PSU vested | **0.6** | — | — |
| Shares repurchased (a) | **(1.4)** | (43.4) | (19.3) |
| Balance at December 31 | **286.0** | 285.8 | 325.3 |

*(a) See Note 17, Share Repurchase Plan.*

The following table presents the calculation of basic and diluted earnings per share:

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In millions) | |
| Income (loss) from continuing operations, net of income taxes | **$ (2,959)** | $ 1,692 | $ 4,036 |
| Less: Net income (loss) attributable to noncontrolling interests | **49** | — | 176 |
| Net income (loss) from continuing operations attributable to Hess Corporation | **(3,008)** | 1,692 | 3,860 |
| Income from discontinued operations, net of income taxes | **(48)** | 682 | 1,186 |
| Less: Net income (loss) attributable to noncontrolling interests | — | 57 | (6) |
| Net income from discontinued operations attributable Hess Corporation | **(48)** | 625 | 1,192 |
| Net income (loss) attributable to Hess Corporation | **$ (3,056)** | $ 2,317 | $ 5,052 |
| **Weighted average common shares outstanding:** | | | |
| Basic | **283.6** | 303.7 | 336.6 |
| Effect of dilutive securities | | | |
| Restricted common stock | **—** | 1.5 | 1.4 |
| Stock options | **—** | 1.8 | 1.7 |
| Performance share units | **—** | 0.7 | 1.2 |
| Diluted | **283.6** | 307.7 | 340.9 |
| **Net income (loss) attributable to Hess Corporation per share:** | | | |
| Basic: | | | |
| Continuing operations | **$ (10.61)** | $ 5.57 | $ 11.47 |
| Discontinued operations | **(0.17)** | 2.06 | 3.54 |
| Net income (loss) per share | **$ (10.78)** | $ 7.63 | $ 15.01 |
| Diluted: | | | |
| Continuing operations | **$ (10.61)** | $ 5.50 | $ 11.33 |
| Discontinued operations | **(0.17)** | 2.03 | 3.49 |
| Net income (loss) per share | **$ (10.78)** | $ 7.53 | $ 14.82 |

The weighted average common shares used in the diluted earnings per share calculations excluded the effect of approximately 6.9 million stock options, 2.9 million restricted stock awards and 1.0 million PSUs from calculating diluted shares as those are anti-dilutive. We excluded 1.4 million of stock options in 2014 (2013: 4.4 million) from calculating weighted average shares used in the diluted earnings per share, because their effect would be anti-dilutive.

In 2015 and 2014, cash dividends declared 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).

## 16. Supplementary Cash Flow Information

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

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In millions) | |
| **Cash Flows From Operating Activities** | | | |
| Interest paid | **$ (331)** | $ (326) | $ (408) |
| Income taxes paid, net of refunds | **(140)** | (455) | (1,353) |
| **Cash Flows From Investing Activities** | | | |
| Capital expenditures incurred - E&P | **(3,753)** | (4,920) | (5,174) |
| Increase (decrease) in related liabilities | **(203)** | 53 | (239) |
| Additions to property, plant and equipment - E&P | **(3,956)** | (4,867) | (5,413) |
| Capital expenditures incurred - Bakken Midstream | **(296)** | (301) | (535) |
| Increase (decrease) in related liabilities | **(69)** | (46) | 11 |
| Additions to property, plant and equipment - Bakken Midstream | **(365)** | (347) | (524) |
| **Cash Flows From Financing Activities** | | | |
| Contribution from formation of Bakken Midstream joint venture | **2,628** | — | — |
| Distributions to partner in Bakken Midstream joint venture | **(332)** | — | — |
| Noncontrolling interests, net related to Continuing operations | **2,296** | — | — |
| **Significant Non-Cash Transactions** | | | |
| Increase in debt due to construction of a floating production system - Tubular Bells Field | **$ —** | $ 68 | $ 116 |

## 17. Share Repurchase Plan

In 2013, our Board of Directors authorized the repurchase of up to $4.0 billion in aggregate purchase price of our common stock. In May 2014, the Board of Directors approved an increase in the program to $6.5 billion. Repurchases under this program were as follows:

| | 2015 | 2014 | 2013 | To Date |
|---|---|---|---|---|
| | | (In millions, except cost per share) | | |
| Total cost of shares repurchased | **$ 91** | $ 3,722 | $ 1,538 | $ 5,351 |
| Total number of shares repurchased | **1.45** | 43.35 | 19.31 | 64.11 |
| Average cost per share (including transaction fees) | **$ 62.76** | $ 85.83 | $ 79.65 | $ 83.45 |

As of December 31, 2015, we are authorized but not required to purchase additional common stock up to a value of $1.15 billion.

## 18. Leased Assets

We and certain of our subsidiaries lease drilling rigs, tankers, office space and other assets for varying periods under contractual obligations accounted for as operating leases. Operating lease expenses for drilling rigs used to drill development wells and successful exploration wells are capitalized. At December 31, 2015, future minimum rental payments applicable to non-cancelable operating leases with remaining terms of one year or more (other than oil and gas property leases) are as follows (in millions):

| | | |
|---|---|---|
| 2016 | $ | 674 |
| 2017 | | 524 |
| 2018 | | 401 |
| 2019 | | 366 |
| 2020 | | 107 |
| Remaining years | | 373 |
| Total minimum lease payments | | 2,445 |
| Less: Income from subleases | | 85 |
| Net minimum lease payments | $ | 2,360 |

Rental expense was as follows:

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In millions) | |
| Total rental expense | **$ 167** | $ 248 | $ 355 |
| Less: Income from subleases | **10** | 17 | 15 |
| Net rental expense | **$ 157** | $ 231 | $ 340 |

## 19. Guarantees, Contingencies and Commitments

### *Guarantees and Contingencies*

At December 31, 2015, we have $32 million in letters of credit for which we are contingently liable. In addition, we are subject to loss contingencies with respect to various claims, lawsuits and other proceedings. A liability is recognized in our consolidated financial statements when it is probable that a loss has been incurred and the amount can be reasonably estimated. If the risk of loss is probable, but the amount cannot be reasonably estimated or the risk of loss is only reasonably possible, a liability is not accrued; however, we disclose the nature of those contingencies. We cannot predict with certainty if, how or when existing claims, lawsuits and proceedings will be resolved or what the eventual relief, if any, may be, particularly for proceedings that are in their early stages of development or where plaintiffs seek indeterminate damages. Numerous issues may need to be resolved, including through lengthy discovery, conciliation and/or arbitration proceedings, or litigation before a loss or range of loss can be reasonably estimated. Subject to the foregoing, in management's opinion, based upon currently known facts and circumstances, the outcome of such lawsuits, claims and proceedings, including the matters described below, is not expected to have a material adverse effect on our financial condition. However, we could incur judgments, enter into settlements or revise our opinion regarding the outcome of certain matters, and such developments could have a material adverse effect on our results of operations in the period in which the amounts are accrued and our cash flows in the period in which the amounts are paid.

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 on December 29, 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, 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 the 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 released upon the establishment of the environmental response trust in connection with the Liquidation Plan.

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 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, 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.

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.

From time to time, we are involved in other judicial and administrative proceedings, including proceedings relating to other environmental matters. We cannot predict with certainty if, how or when such proceedings will be resolved or what the eventual relief, if any, may be, particularly for proceedings that are in their early stages of development or where plaintiffs seek indeterminate damages. Numerous issues may need to be resolved, including through potentially lengthy discovery and determination of important factual matters before a loss or range of loss can be reasonably estimated for any proceeding. Subject to the foregoing, in management's opinion, based upon currently known facts and circumstances, the outcome of such proceedings is not expected to have a material adverse effect on our financial condition, results of operations or cash flows.

***Unconditional Purchase Obligations and Commitments***

The following table shows aggregate information for certain unconditional purchase obligations and commitments at December 31, 2015 which are not included elsewhere within these *Consolidated Financial Statements*:

| | | Payments Due by Period | | | |
|---|---|---|---|---|---|
| | Total | 2016 | 2017 and 2018 | 2019 and 2020 | Thereafter |
| | (In millions) | | | | |
| Capital expenditures | $ 1,750 | $ 1,503 | $ 247 | $ — | $ — |
| Operating expenses | 548 | 384 | 108 | 32 | 24 |
| Transportation and related contracts | 1,598 | 121 | 453 | 433 | 591 |

## 20. Segment Information

We currently have two operating segments, Exploration and Production and Bakken Midstream. The Exploration and Production operating segment explores for, develops, produces, purchases and sells crude oil, natural gas liquids and natural gas with production operations 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 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 located in the Bakken shale play of North Dakota. All unallocated costs are reflected under Corporate, Interest and Other.

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

| 2015 | Exploration and Production | Bakken Midstream | Corporate, Interest and Other | Eliminations | Total |
|---|---|---|---|---|---|
| Operating Revenues - Third parties | $ 6,636 | $ — | $ — | $ — | $ 6,636 |
| Intersegment Revenues | — | 564 | — | (564) | — |
| Operating Revenues | $ 6,636 | $ 564 | $ — | $ (564) | $ 6,636 |
| Net income (loss) from continuing operations attributable to Hess Corporation | $ (2,717) | $ 86 | $ (377) | $ — | $ (3,008) |
| Interest expense | — | 10 | 331 | — | 341 |
| Depreciation, depletion and amortization | 3,852 | 88 | 15 | — | 3,955 |
| Impairment | 1,616 | — | — | — | 1,616 |
| Provision (benefit) for income taxes | (1,111) | 52 | (240) | — | (1,299) |
| Investment in affiliates | 154 | — | — | — | 154 |
| Identifiable assets | 28,863 | 2,761 | 2,571 | — | 34,195 |
| Capital Expenditures | 3,753 | 296 | — | — | 4,049 |

| 2014 | Exploration and Production | Bakken Midstream | Corporate, Interest and Other | Eliminations | Total |
|---|---|---|---|---|---|
| Operating Revenues - Third parties | $ 10,737 | $ — | $ — | $ — | $ 10,737 |
| Intersegment Revenues | — | 319 | — | (319) | — |
| Operating Revenues | $ 10,737 | $ 319 | $ — | $ (319) | $ 10,737 |
| Net income (loss) from continuing operations attributable to Hess Corporation | $ 2,086 | $ 10 | $ (404) | $ — | $ 1,692 |
| Interest expense | — | 2 | 321 | — | 323 |
| Depreciation, depletion and amortization | 3,140 | 70 | 14 | — | 3,224 |
| Provision (benefit) for income taxes | 989 | 7 | (252) | — | 744 |
| Investment in affiliates | 151 | — | — | — | 151 |
| Identifiable assets | 32,742 | 2,465 | 2,042 | — | 37,249 |
| Capital Expenditures | 4,920 | 301 | 53 | — | 5,274 |

| 2013 | Exploration and Production | Bakken Midstream | Corporate, Interest and Other | Eliminations | Total |
|---|---|---|---|---|---|
| Operating Revenues - Third parties | $ 11,762 | $ 143 | $ — | $ — | $ 11,905 |
| Intersegment Revenues | 125 | 127 | — | (252) | — |
| Operating Revenues | $ 11,887 | $ 270 | $ — | $ (252) | $ 11,905 |
| Net income (loss) from continuing operations attributable to Hess Corporation | $ 4,439 | $ (136) | $ (443) | $ — | $ 3,860 |
| Interest Expense | — | — | 406 | — | 406 |
| Depreciation, depletion and amortization | 2,638 | 33 | 16 | — | 2,687 |
| Impairment | 289 | — | — | — | 289 |
| Provision (benefit) for income taxes | 912 | (81) | (266) | — | 565 |
| Investment in affiliates | 109 | — | 397 | — | 506 |
| Capital Expenditures | 5,174 | 535 | 58 | — | 5,767 |

The following table presents financial information by major geographic area:

| | United States | Europe | Africa | Asia and Other Countries | Corporate, Interest and other | Total |
|---|---|---|---|---|---|---|
| | | | (In millions) | | | |
| **2015** | | | | | | |
| Operating revenues | **$ 4,150** | **$ 870** | **$ 945** | **$ 671** | **$ —** | **$ 6,636** |
| Net income (loss) from continuing operations attributable to Hess Corporation | **(1,834)** | **(408)** | **(274)** | **(115)** | **(377)** | **(3,008)** |
| Depreciation, depletion and amortization | **2,449** | **635** | **539** | **317** | **15** | **3,955** |
| Impairments | **986** | **279** | **100** | **251** | **—** | **1,616** |
| Provision (benefit) for income taxes | **(522)** | **(84)** | **(48)** | **(405)** | **(240)** | **(1,299)** |
| Identifiable assets | **18,372** | **6,207** | **2,178** | **4,867** | **2,571** | **34,195** |
| Property, plant and equipment (net) (a) | **15,729** | **5,300** | **1,682** | **3,520** | **121** | **26,352** |
| Capital expenditures | **2,727** | **297** | **160** | **865** | **—** | **4,049** |
| **2014** | | | | | | |
| Operating revenues | $ 6,270 | $ 1,557 | $ 2,002 | $ 908 | $ — | $ 10,737 |
| Net income (loss) from continuing operations attributable to Hess Corporation | 654 | 226 | 545 | 671 | (404) | 1,692 |
| Depreciation, depletion and amortization | 1,751 | 683 | 487 | 289 | 14 | 3,224 |
| Provision (benefit) for income taxes | 446 | 91 | 435 | 24 | (252) | 744 |
| Identifiable assets | 17,729 | 7,730 | 3,002 | 6,746 | 2,042 | 37,249 |
| Property, plant and equipment (net) (a) | 15,595 | 6,339 | 2,235 | 3,232 | 116 | 27,517 |
| Capital expenditures | 3,467 | 524 | 399 | 831 | 53 | 5,274 |
| **2013** | | | | | | |
| Operating revenues | $ 6,076 | $ 1,337 | $ 2,736 | $ 1,756 | $ — | $ 11,905 |
| Net income (loss) from continuing operations attributable to Hess Corporation | 777 | 2,051 | 594 | 881 | (443) | 3,860 |
| Depreciation, depletion and amortization | 1,393 | 484 | 518 | 276 | 16 | 2,687 |
| Impairments | — | — | — | 289 | — | 289 |
| Provision (benefit) for income taxes | 495 | (646) | 767 | 215 | (266) | 565 |
| Capital expenditures | 3,613 | 689 | 578 | 829 | 58 | 5,767 |

(a) *Of the total Europe, Property, plant and equipment (net), Norway represented $4,108 million in 2015 (2014: $5,246 million).*

## 21. Related Party Transactions

The following table presents our related party transactions:

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In millions) | |
| **Purchases:** | | | |
| HOVENSA | $ — | $ — | $ — |
| Bayonne Energy Center LLC | — | — | 38 |
| **Sales:** | | | |
| WilcoHess (a) | — | 211 | 2,828 |
| HOVENSA | — | 31 | 90 |

(a) *We acquired our partners' 56% interest in WilcoHess in January 2014 for approximately $290 million. See Note 3, Discontinued Operations.*

## 22. Financial Risk Management Activities

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

***Corporate Financial Risk Management Activities:*** Financial risk management activities include transactions designed to reduce risk in the selling prices of crude oil or natural gas we produced or by reducing our exposure to foreign currency or interest rate movements. Generally, futures, swaps or option strategies may be used to fix the forward selling price of a portion of our crude oil or natural gas production. Forward contracts may also be used to purchase certain currencies in which we conduct the business with the intent of reducing exposure to foreign currency fluctuations. These forward contracts comprise various currencies, primarily the British Pound and Danish Krone. Interest rate swaps may be used to convert interest payments on certain long-term debt from fixed to floating rates.

Gross notional amounts of both long and short positions are presented in the volume tables beginning below. These amounts include long and short positions that offset in closed positions and have not reached contractual maturity. Gross notional amounts do not quantify risk or represent assets or liabilities of the Corporation, but are used in the calculation of cash settlements under the contracts.

The gross volumes of the financial risk management derivative contracts outstanding at December 31, were as follows:

| | 2015 | 2014 |
|---|---|---|
| Foreign exchange (millions of USD) | **$ 967** | $ 1,189 |
| Interest rate swaps (millions of USD) | **$ 1,300** | $ 1,300 |

The table below reflects the gross and net fair values of the risk management derivative instruments, all of which are based on Level 2 inputs:

| | Accounts Receivable | Accounts Payable |
|---|---|---|
| | (In millions) | |
| **December 31, 2015** | | |
| **Derivative contracts designated as hedging instruments** | | |
| Interest rate | **$ 3** | **$ —** |
| Total derivative contracts designated as hedging instruments | **3** | **—** |
| **Derivative contracts not designated as hedging instruments** | | |
| Foreign exchange | **19** | **(3)** |
| Total derivative contracts not designated as hedging instruments | **19** | **(3)** |
| Gross fair value of derivative contracts | **22** | **(3)** |
| Master netting arrangements | **(3)** | **3** |
| **Net fair value of derivative contracts** | **$ 19** | **$ —** |
| **December 31, 2014** | | |
| **Derivative contracts designated as hedging instruments** | | |
| Interest rate | $ 39 | $ — |
| Total derivative contracts designated as hedging instruments | 39 | — |
| **Derivative contracts not designated as hedging instruments** | | |
| Foreign exchange | 29 | — |
| Total derivative contracts not designated as hedging instruments | 29 | — |
| Gross fair value of derivative contracts | 68 | — |
| **Net fair value of derivative contracts** | $ 68 | $ — |

Derivative contracts designated as hedging instruments:

*Commodity:* In 2015, crude oil price hedging contracts increased E&P Sales and other operating revenues by $126 million, including losses of $48 million associated with changes in the time value of crude oil collars. In 2014 and 2013, crude oil price hedging contracts increased E&P Sales and other operating revenues by $193 million and $39 million, respectively.

*Interest rate swaps:* At December 31, 2015, we had interest rate swaps with gross notional amounts of $1,300 million (2014: $1,300 million), which were designated as fair value hedges. During 2015, we settled existing interest rate swaps and received cash proceeds of $41 million. Changes in the fair value of interest rate swaps and the hedged fixed-rate debt are recorded in Interest expense in the *Statement of Consolidated Income*. In 2015, we recorded an increase of $4 million, excluding accrued interest, in the fair value of interest rate swaps and a corresponding adjustment in the carrying value of the hedged fixed-rate debt (2014: $1 million increase; 2013: $35 million decrease).

Derivative contracts not designated as hedging instruments:

*Foreign exchange*: Total foreign exchange gains and losses are reported in Other, net in Revenues and non-operating income in the *Statement of Consolidated Income* and amounted to a loss of $21 million in 2015 (2014: loss of $43 million; 2013: loss of $54 million) and includes gains or losses on foreign exchange contracts that are not designated as hedges amounting to a gain of $98 million in 2015 (2014: gain of $117 million; 2013: loss of $39 million). The after-tax foreign currency translation adjustments included in the *Statement of Consolidated Comprehensive Income* amounted to a loss of $344 million for the year-ended December 31, 2015 (2014: loss of $756 million; 2013: loss of $164 million). Cumulative currency translation adjustments reduced shareholders' equity by $1,101 million at December 31, 2015 and $757 million at December 31, 2014.

***Trading Activities:*** In February 2015, we sold our interest in our energy trading joint venture, HETCO, which was subsequently, renamed Hartree Partners, LP (Hartree). Pursuant to the terms of the sale, Hartree was permitted to utilize our guarantees issued in favor of Hartree's existing counterparties until November 12, 2015, provided that new trades were for a period of one year or less, complied with certain credit requirements, and net exposures remained within value at risk limits previously applied by us. The guarantees remain in effect until the qualifying trades outstanding at November 12, 2015 mature. We have the right to seek reimbursement from Hartree and a separate Hartree credit support facility upon any counterparty draw on the applicable guarantee from us. No draws on the guaranteed trades have occurred through December 31, 2015. A liability of $10 million associated with the guarantee is included in Other accrued liabilities at December 31, 2015.

***Credit Risk:*** We are exposed to credit risks that may at times be concentrated with certain counterparties, groups of counterparties or customers. Accounts receivable are generated from a diverse domestic and international customer base. As of December 31, 2015, our Accounts receivable —Trade related to continuing operations were concentrated with the following counterparty industry segments: Integrated Oil Companies — 58%, Governments — 18%, Financial Institutions — 10% and Other — 14%. We reduce risk related to certain counterparties, where applicable, by using master netting arrangements and requiring collateral, generally cash or letters of credit.

At December 31, 2015, we had outstanding letters of credit totaling $113 million (2014: $397 million, of which $240 million related to discontinued operations).

***Fair Value Measurement:*** We have other short-term financial instruments, primarily cash equivalents, accounts receivable and accounts payable, for which the carrying value approximated fair value at December 31, 2015 and December 31, 2014. In addition, the disclosure for fair value of long-term debt in *Note 8, Debt* was based on Level 2 inputs.

## 23. Subsequent Events

***HOVENSA Bankruptcy Settlement:*** On January 4, 2016, the sale of HOVENSA's terminal and refinery assets to Limetree Bay Terminals, LLC ("Limetree"), an affiliate of ArcLight Capital Partners, LLC, closed. 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, 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, which were effective on the effective date of the Liquidation Plan. In connection with the Liquidation Plan and HOVENSA's asset sale, we relinquished our claims against HOVENSA to recover the 2012 and 2015 promissory notes issued by HOVENSA. In addition, we assumed the HOVENSA pension plan upon the effective date of the Liquidation Plan. 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.

***Hess Common and Preferred Stock Issuance*:** In February 2016, we issued 28,750,000 shares of common stock and depositary shares representing 575,000 shares of 8% Series A Mandatory Convertible Preferred Stock (Convertible Preferred Stock), par value $1 per share, with a liquidation preference of $1,000 per share, for total net proceeds of approximately $1.6 billion after deducting underwriting discounts, commissions, and estimated offering expenses. Unless converted earlier, each share of Convertible Preferred Stock will automatically convert into between 21.822 shares and 25.642 shares of our common stock based on the average share price over a period of twenty consecutive trading days ending prior to February 1, 2019 (the "Final Average Price"), subject to anti-dilution adjustments.

We also entered into capped call transactions that are expected generally to reduce the potential dilution to our common stock upon conversion of the Convertible Preferred Stock if the Final Average Price exceeds $45.83 per share, subject to anti-dilution adjustments. The number of common shares to be delivered by the counterparties to us will be the value of the capped call transactions at conversion divided by the Final Average Price. The value of the capped call transactions will be zero if the Final Average Price is $45.83 or less and can be up to the capped value of approximately $98 million if the Final Average Price is $53.625 or higher. For any Final Average Price between $45.83 and $53.625, the value of the capped call transactions will be 12.55 million covered shares multiplied by the difference between the Final Average Price and $45.83.

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

During the three-year period ended December 31, 2015, we produced crude oil, natural gas liquids and/or natural gas principally in the United States (U.S.), Europe (Norway, Denmark, Russia and the United Kingdom), Africa (Equatorial Guinea, Libya and Algeria) and Asia and Other (the Joint Development Area of Malaysia/Thailand (JDA), Malaysia, Thailand, Azerbaijan and Indonesia). Exploration activities were also conducted, or are planned, in certain of these areas as well as additional countries. See *Note 9*, *Dispositions* in the *Notes to the Consolidated Financial Statements*.

## Costs Incurred in Oil and Gas Producing Activities

| For the Years Ended December 31 | Total | United States | Europe (c) | Africa | Asia and Other |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| **2015** | | | | | |
| Property acquisitions | | | | | |
| Unproved | **$ 22** | **$ 22** | **$ —** | **$ —** | **$ —** |
| Proved | **—** | **—** | **—** | **—** | **—** |
| Exploration (a) | **622** | **255** | **1** | **3** | **363** |
| Production and development capital expenditures (b) | **3,549** | **2,414** | **310** | **155** | **670** |
| **2014** | | | | | |
| Property acquisitions | | | | | |
| Unproved | $ 88 | $ 21 | $ — | $ — | $ 67 |
| Proved | — | — | — | — | — |
| Exploration (a) | 763 | 354 | 16 | 113 | 280 |
| Production and development capital expenditures (b) | 4,727 | 2,991 | 778 | 319 | 639 |
| **2013** | | | | | |
| Property acquisitions | | | | | |
| Unproved | $ 56 | $ 55 | $ — | $ — | $ 1 |
| Proved | — | — | — | — | — |
| Exploration (a) | 1,044 | 592 | 98 | 119 | 235 |
| Production and development capital expenditures (b) | 5,131 | 2,724 | 1,008 | 586 | 813 |

*(a) Includes $45 million of exploration costs incurred for unconventional assets in 2015 (2014; $283 million; 2013: $560 million).*
*(b) Includes $151 million related to the accruals and revisions for asset retirement obligations in 2015 (2014: $326 million; 2013: $615 million).*
*(c) Costs incurred in oil and gas producing activities in Norway, were as follows for the years ended December 31:*

| | *2015* | *2014* | *2013* |
|---|---|---|---|
| | | *(In millions)* | |
| *Property Acquisitions* | *$ —* | *$ —* | *$ —* |
| *Exploration* | *—* | *—* | *6* |
| *Production and development capital expenditures** | ***92*** | *525* | *781* |

* *Includes accruals and revisions for asset retirement obligations.*

## Capitalized Costs Relating to Oil and Gas Producing Activities

| | At December 31, 2015 | At December 31, 2014 |
|---|---|---|
| | (In millions) | |
| Unproved properties | **$ 958** | $ 1,468 |
| Proved properties | **4,202** | 4,211 |
| Wells, equipment and related facilities | **38,738** | 38,263 |
| Total costs | **43,898** | 43,942 |
| Less: Reserve for depreciation, depletion, amortization and lease impairment | **20,025** | 18,617 |
| Net capitalized costs | **$ 23,873** | $ 25,325 |

## Results of Operations for Oil and Gas Producing Activities

The results of operations shown below exclude non-oil and gas producing activities, primarily gains on sales of oil and gas properties, sales of purchased crude oil and natural gas, interest expense and other non-operating income. Therefore, these results are on a different basis than the net income from E&P operations reported in Management's Discussion and Analysis of Financial Condition and Results of Operations and in *Note 20, Segment Information* in the *Notes to the Consolidated Financial Statements.*

| For the Years Ended December 31 | Total | United States | Europe (a) | Africa | Asia and Other | |
|---|---|---|---|---|---|---|
| | | | (In millions) | | | |
| **2015** | | | | | | |
| Sales and other operating revenues | **$ 5,201** | **$ 2,706** | **$ 870** | **$ 956** | **$ 669** | |
| Costs and expenses | | | | | | |
| Operating costs and expenses | **1,764** | **786** | **402** | **426** | **150** | |
| Production and severance taxes | **146** | **138** | **2** | **4** | **2** | |
| Bakken Midstream tariffs | **449** | **449** | **—** | **—** | **—** | |
| Exploration expenses, including dry holes and lease impairment | **881** | **255** | **1** | **183** | **442** | |
| General and administrative expenses | **317** | **262** | **31** | **4** | **20** | |
| Depreciation, depletion and amortization | **3,852** | **2,361** | **635** | **539** | **317** | |
| Impairment | **1,616** | **986** | **279** | **100** | **251** | |
| Total costs and expenses | **9,025** | **5,237** | **1,350** | **1,256** | **1,182** | |
| Results of operations before income taxes | **(3,824)** | **(2,531)** | **(480)** | **(300)** | **(513)** | |
| Provision (benefit) for income taxes | **(1,117)** | **(588)** | **(76)** | **(48)** | **(405)** | |
| Results of operations | **$ (2,707)** | **$ (1,943)** | **$ (404)** | **$ (252)** | **$ (108)** | |
| **2014** | | | | | | |
| Sales and other operating revenues | $ 8,839 | $ 4,461 | $ 1,540 | $ 1,962 | $ 876 | |
| Costs and expenses | | | | | | |
| Operating costs and expenses | 1,815 | 731 | 461 | 441 | 182 | |
| Production and severance taxes | 275 | 240 | 3 | — | 32 | |
| Bakken Midstream tariffs | 212 | 212 | — | — | — | |
| Exploration expenses, including dry holes and lease impairment | 840 | 359 | 90 | 36 | 355 | |
| General and administrative expenses | 325 | 270 | — | 16 | 39 | |
| Depreciation, depletion and amortization | 3,140 | 1,681 | 683 | 487 | 289 | |
| Total costs and expenses | 6,607 | 3,493 | 1,237 | 980 | 897 | |
| Results of operations before income taxes | 2,232 | 968 | 303 | 982 | (21) | |
| Provision for income taxes | 919 | 392 | 101 | 435 | (9) | |
| Results of operations | $ 1,313 | $ 576 | $ 202 | $ 547 | $ (12) | **(b)** |
| **2013** | | | | | | |
| Sales and other operating revenues | $ 10,045 | $ 4,318 | $ 1,482 | $ 2,671 | $ 1,574 | |
| Costs and expenses | | | | | | |
| Operating costs and expenses | 1,996 | 675 | 539 | 448 | 334 | |
| Production and severance taxes | 372 | 232 | 98 | 3 | 39 | |
| Exploration expenses, including dry holes and lease impairment | 1,031 | 371 | 114 | 323 | 223 | |
| General and administrative expenses | 362 | 203 | 79 | 17 | 63 | |
| Depreciation, depletion and amortization | 2,638 | 1,360 | 484 | 518 | 276 | |
| Impairment | 289 | — | — | — | 289 | |
| Total costs and expenses | 6,688 | 2,841 | 1,314 | 1,309 | 1,224 | |
| Results of operations before income taxes | 3,357 | 1,477 | 168 | 1,362 | 350 | |
| Provision for income taxes (c) | 1,561 | 565 | 60 | 767 | 169 | |
| Results of operations | $ 1,796 | $ 912 | $ 108 | $ 595 | $ 181 | **(b)** |

(a) *Results of operations for oil and gas producing activities in Norway were as follows for the years ended December 31.*

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | (In millions) | |
| *Sales and other operating revenues* | **$ 635** | $ 1,102 | $ 860 |
| *Cost and expenses* | | | |
| *Operating costs and expenses* | **314** | 376 | 376 |
| *Production and severance taxes* | **2** | 3 | 6 |
| *Exploration expenses, including dry holes and lease impairment* | **—** | — | 6 |
| *General and administrative expenses* | **3** | 4 | 8 |
| *Depreciation, depletion and amortization* | **501** | 513 | 364 |
| *Total costs and expenses* | **820** | 896 | 760 |
| *Results of operations before income taxes* | **(185)** | 206 | 100 |
| *Provision(benefit) for income taxes* | **(171)** | 103 | 36 |
| *Results of operations* | **$ (14)** | $ 103 | $ 64 |

(b) *Includes other countries where exploration activities are ongoing. Net losses for other countries were $266 million in 2014 and $223 million in 2013.*
(c) *Excludes a deferred tax benefit of $674 million which represents the effect of the Denmark hydrocarbon income tax law change to the Chapter 3A regime in December 2013.*

## Proved Oil and Gas Reserves

Our proved oil and gas reserves are calculated in accordance with the Securities and Exchange Commission (SEC) regulations and the requirements of the Financial Accounting Standards Board. Proved oil and gas reserves are quantities, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from known reservoirs under existing economic conditions, operating methods and government regulations. Our estimation of net recoverable quantities of liquid hydrocarbons and natural gas is a highly technical process performed by our internal teams of geoscience and reservoir engineering professionals. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principals and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir is based on the maturity of the reservoir, the completeness of the subsurface data available at the time of the estimate, the stage of reservoir development and the production history. Where applicable, reliable technologies may be used in reserve estimation, as defined in the SEC regulations. These technologies, including computational methods, must have been field tested and demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In order for reserves to be classified as proved, any required government approvals must be obtained and depending on the cost of the project, either senior management or the Board of Directors must commit to fund the development. Our proved reserves are subject to certain risks and uncertainties, which are discussed in *Item 1A. Risk Factors* of this Form 10-K.

### Internal Controls

The Corporation maintains internal controls over its oil and gas reserve estimation processes which are administered by the Corporation's Director, Global Reserves and its Chief Financial Officer. Estimates of reserves are prepared by technical staff who work directly with the oil and gas properties using standard reserve estimation guidelines, definitions and methodologies. Each year, reserve estimates for a selection of the Corporation's assets are subject to internal technical audits and reviews. In addition, an independent third-party reserve engineer reviews and audits a significant portion of the Corporation's reported reserves (see pages 86 through 89). Reserve estimates are reviewed by senior management and the Board of Directors.

### Qualifications

The person primarily responsible for overseeing the preparation of the Corporation's oil and gas reserves during 2015 was Mr. David DuBois, Director Global Reserves. Mr. DuBois is a member of the Society of Petroleum Engineers and has over 30 years of experience in the oil and gas industry with a BS degree in Petroleum Engineering. His experience has been primarily focused on oil and gas subsurface understanding and reserves estimation in both domestic and international areas. Mr. DuBois is responsible for the Corporation's Global Reserves group, which is the internal organization responsible for establishing the policies and processes used within the operating units to estimate reserves and perform internal technical reserve audits and reviews.

**Reserves Audit**

We engaged the consulting firm of DeGolyer and MacNaughton (D&M) to perform an audit of the internally prepared reserve estimates on certain fields aggregating 83% of 2015 year-end reported reserve quantities on a barrel of oil equivalent basis (2014: 80%). The purpose of this audit was to provide additional assurance on the reasonableness of internally prepared reserve estimates and compliance with SEC regulations. The D&M letter report, dated February 3, 2016, on the Corporation's estimated oil and gas reserves was prepared using standard geological and engineering methods generally recognized in the petroleum industry. D&M is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over 70 years. D&M's letter report on the Corporation's December 31, 2015 oil and gas reserves is included as an exhibit to this Form 10-K. While the D&M report should be read in its entirety, the report concludes that for the properties reviewed by D&M, the total net proved reserve estimates prepared by Hess and audited by D&M, in the aggregate, differed by less than 1% of total audited net proved reserves on a barrel of oil equivalent basis. The report also includes among other information, the qualifications of the technical person primarily responsible for overseeing the reserve audit.

Following are the Corporation's proved reserves:

| | Crude Oil, Condensate & Natural Gas Liquids (Millions of barrels) | | | | | Natural Gas (Millions of mcf) | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **United States** | **Europe (g)** | **Africa** | **Asia** | **Total** | **United States** | **Europe (g)** | **Asia and Africa (h)** | **Total** |
| **Net Proved Developed and Undeveloped Reserves** | | | | | | | | | |
| At January 1, 2013 | 473 | 416 | 234 | 48 | 1,171 (b) | 400 | 357 | 1,538 | 2,295 |
| Revisions of previous estimates (a) | (55) | (24) | — | — | (79) | (12) | (66) | (5) | (83) |
| Extensions, discoveries and other additions | 211 | 4 | 2 | — | 217 | 131 | 4 | 7 | 142 |
| Sales of minerals in place | (2) | (89) | (4) | (18) | (113) | (4) | (47) | (108) | (159) |
| Production (f) | (45) | (16) | (22) | (5) | (88) | (51) | (10) | (159) | (220) |
| At December 31, 2013 | 582 | 291 | 210 | 25 | 1,108 | 464 | 238 | 1,273 | 1,975 |
| Revisions of previous estimates (a) | (34) | (20) | (8) | 1 | (61) | 58 | (31) | 23 | 50 |
| Extensions, discoveries and other additions | 137 | 34 | 6 | 1 | 178 | 184 | 26 | 192 | 402 |
| Sales of minerals in place | — | — | — | (19) | (19) | (20) | — | (329) | (349) |
| Production (f) | (54) | (14) | (20) | (1) | (89) | (66) | (13) | (118) | (197) |
| At December 31, 2014 | 631 | 291 | 188 | 7 | 1,117 | 620 | 220 | 1,041 | 1,881 |
| Revisions of previous estimates (a) | **(199)** | **(54)** | **9** | **(1)** | **(245)** | **(112)** | **24** | **(121)** | **(209)** |
| Extensions, discoveries and other additions | **56** | **7** | **1** | **—** | **64** | **102** | **5** | **3** | **110** |
| Sales of minerals in place | **—** | **—** | **(8)** | **—** | **(8)** | **—** | **—** | **—** | **—** |
| Production (f) | **(68)** | **(14)** | **(18)** | **(1)** | **(101)** | **(105)** | **(15)** | **(108)** | **(228)** |
| At December 31, 2015 (c) | **420** | **230** | **172** | **5** | **827** | **505** | **234** | **815** | **1,554** |
| **Net Proved Developed Reserves (d)** | | | | | | | | | |
| At January 1, 2013 | 280 | 181 | 188 | 27 | 676 | 232 | 190 | 798 | 1,220 |
| At December 31, 2013 | 278 | 126 | 185 | 17 | 606 | 279 | 104 | 727 | 1,110 |
| At December 31, 2014 | 320 | 123 | 163 | 3 | 609 | 350 | 96 | 473 | 919 |
| At December 31, 2015 | **304** | **126** | **148** | **5** | **583** | **368** | **123** | **780** | **1,271** |
| **Net Proved Undeveloped Reserves (e)** | | | | | | | | | |
| At January 1, 2013 | 193 | 235 | 46 | 21 | 495 | 168 | 167 | 740 | 1,075 |
| At December 31, 2013 | 304 | 165 | 25 | 8 | 502 | 185 | 134 | 546 | 865 |
| At December 31, 2014 | 311 | 168 | 25 | 4 | 508 | 270 | 124 | 568 | 962 |
| At December 31, 2015 | **116** | **104** | **24** | — | **244** | **137** | **111** | **35** | **283** |

*(a) Includes the impact of changes in selling prices on the reserve estimates for production sharing contracts with cost recovery provisions. Revisions included an increase to crude oil, condensate and natural gas liquids reserves of 5 million barrels (2014: 1 million barrels increase; 2013: 0.1 million barrels increase) and an increase to natural gas reserves of 42 million mcf in 2015 (2014: 7 million mcf increase; 2013: 9 million mcf reduction), due to changes in selling prices.*

*(b) Includes 8 million barrels as of January 1, 2013 of crude oil reserves related to a noncontrolling interest. The joint venture including the noncontrolling interest was sold in April 2013.*
*(c) Excludes approximately 255 million mcf of carbon dioxide gas for sale or use in company operations.*
*(d) Natural gas liquids net proved developed reserves amounted to 63 million barrels, 65 million barrels, 61 million barrels at December 31, 2015, 2014, and 2013, respectively, and 76 million barrels at January 1, 2013. At December 31, 2015 the United States contained 81% of our net proved developed natural gas liquids reserves (2014: 85%, 2013: 83%) and Norway contained 19% (2014: 15%; 2013: 15%).*
*(e) Natural gas liquids net proved undeveloped reserves amounted to 38 million barrels, 80 million barrels, 75 million barrels at December 31, 2015, 2014, and 2013, respectively, and 60 million barrels at January 1, 2013. At December 31, 2015 the United States contained 58% of our net proved undeveloped natural gas liquids reserves (2014: 79%, 2013: 83%) and Norway contained 42% (2014: 21%; 2013: 15%).*
*(f) Natural gas production includes volumes used for fuel.*
*(g) Proved reserves in Norway were as follows:*

| | Crude Oil, Condensate & Natural Gas Liquids | | | Natural Gas | | |
|---|---|---|---|---|---|---|
| | **2015** | 2014 | 2013 | **2015** | 2014 | 2013 |
| | (Millions of barrels) | | | (Millions of mcf) | | |
| At January 1 | **256** | 256 | 284 | **180** | 198 | 219 |
| Revisions of previous estimates | **(53)** | (22) | (21) | **18** | (33) | (16) |
| Extensions, discoveries and other additions | **5** | 32 | — | **3** | 24 | — |
| Sales of minerals in place | **—** | — | — | **—** | — | — |
| Production | **(10)** | (10) | (7) | **(10)** | (9) | (5) |
| At December 31 | **198** | 256 | 256 | **191** | 180 | 198 |
| Net Proved Developed Reserves at December 31 (d) | **98** | 95 | 107 | **84** | 67 | 87 |
| Net Proved Undeveloped Reserves at December 31 (e) | **100** | 161 | 149 | **107** | 113 | 111 |

*(h) Natural gas reserves in Africa were 148 million mcf at December 31, 2015 (2014: 155 million mcf; 2013:160 million mcf).*

Proved reserves are calculated using the average price during the twelve month period before December 31 determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the year, unless prices are defined by contractual agreements, excluding escalations based on future conditions. Crude oil prices used in the determination of proved reserves at December 31, 2015 were $55.10 per barrel for Brent (2014: $101.35; 2013: $108.85) and $50.13 per barrel for WTI (2014: $94.42; 2013: $97.33). Negative reserve revisions in 2015, associated with lower crude oil prices, reduced proved reserves at December 31, 2015 by 234 million barrels of oil equivalent (boe).

At December 31, 2015, spot prices for West Texas Intermediate crude oil closed at $37.13 per barrel and averaged $31.78 per barrel in January 2016. If crude oil prices stay at levels below that used in determining 2015 proved reserves, we may recognize further negative revisions up to a significant majority of our December 31, 2015 proved undeveloped reserves. In addition, we may recognize negative revisions to proved developed reserves, which can vary significantly by asset due to differing operating cost structures. Conversely, price increases in 2016 above those used in determining 2015 proved reserves could result in positive revisions to proved developed and proved undeveloped reserves at December 31, 2016. It is difficult to estimate the magnitude of any potential net negative or positive change in proved reserves as of December 31, 2016, due to a number of factors that are currently unknown, including 2016 crude oil prices, any revisions based on 2016 reservoir performance, and the levels to which industry costs will change in response to movements in commodity prices.

In 2015, total proved reserve additions amounted to 82 million boe (52 million barrels of crude oil, 12 million barrels of natural gas liquids and 110 million mcf of natural gas) of which 73 million boe resulted from new wells drilled in the Bakken shale play in North Dakota. Total net negative revisions of proved reserves in 2015, includes a reduction of 234 million boe driven by lower commodity prices, a reduction of 48 million boe from changes in our planned drilling schedule and an increase in technical revisions of 2 million boe primarily related to improved well performance. Additions and revisions to proved undeveloped reserves are discussed in further detail below.

In 2014, total proved reserve additions in the United States were 115 million barrels of crude oil, 22 million barrels of natural gas liquids and 184 million mcf of natural gas primarily from the Bakken oil shale play in North Dakota, Utica shale in Ohio and the Gulf of Mexico. New wells completed in 2014 added proved reserves of 16 million barrels of crude oil, 5 million barrels of natural gas liquids and 58 million mcf of natural gas. Other additions and revisions to proved reserves primarily relate to proved undeveloped reserves which are discussed in further detail below.

**Proved Undeveloped Reserves**

The December 31, 2015 oil and gas proved reserve estimates disclosed above include 291 million boe, classified as proved undeveloped reserves (2014: 669 million boe; 2013: 646 million boe). The composition of proved undeveloped reserves is as follows:

| | Crude Oil, Condensate & Natural Gas Liquids | | | | | Natural Gas | | | |
|---|---|---|---|---|---|---|---|---|---|
| | United States | Europe | Africa | Asia | Total | United States | Europe | Asia and Africa | Total |
| | (Millions of barrels) | | | | | (Millions of mcf) | | | |
| **Net Proved Undeveloped Reserves** | | | | | | | | | |
| At January 1, 2013 | 193 | 235 | 46 | 21 | 495 | 168 | 167 | 740 | 1,075 |
| Revisions of previous estimates | (42) | (13) | (5) | (2) | (62) | (46) | (20) | (88) | (154) |
| Extensions, discoveries and other additions | 190 | 3 | 1 | — | 194 | 90 | 4 | 7 | 101 |
| Transfers to proved developed reserves | (37) | (21) | (13) | (1) | (72) | (27) | (13) | (58) | (98) |
| Sales of minerals in place (a) | — | (39) | (4) | (10) | (53) | — | (4) | (55) | (59) |
| At December 31, 2013 | 304 | 165 | 25 | 8 | 502 | 185 | 134 | 546 | 865 |
| Revisions of previous estimates | (46) | (8) | — | — | (54) | 12 | (16) | (12) | (16) |
| Extensions, discoveries and other additions | 117 | 34 | 4 | 1 | 156 | 126 | 26 | 188 | 340 |
| Transfers to proved developed reserves | (64) | (23) | (4) | — | (91) | (53) | (20) | (45) | (118) |
| Sales of minerals in place (b) | — | — | — | (5) | (5) | — | — | (109) | (109) |
| At December 31, 2014 | 311 | 168 | 25 | 4 | 508 | 270 | 124 | 568 | 962 |
| Revisions of previous estimates | **(181)** | **(57)** | **(1)** | **(1)** | **(240)** | **(132)** | **—** | **(180)** | **(312)** |
| Extensions, discoveries and other additions | **33** | **7** | **—** | **—** | **40** | **52** | **5** | **(1)** | **56** |
| Transfers to proved developed reserves | **(47)** | **(14)** | **—** | **(3)** | **(64)** | **(53)** | **(18)** | **(352)** | **(423)** |
| Sales of minerals in place | **—** | **—** | **—** | **—** | **—** | **—** | **—** | **—** | **—** |
| At December 31, 2015 | **116** | **104** | **24** | **—** | **244** | **137** | **111** | **35** | **283** |

*(a) In 2013, the Corporation divested of its operations in Azerbaijan and Russia, as well as the Natuna Field in Indonesia.*
*(b) In 2014, the Corporation divested of its remaining operations in Indonesia and Thailand.*

*Extensions, discoveries and other additions ('Additions')*

*2015:* In the United States, we recognized additions of 29 million boe in the Bakken shale play and 13 million boe related to the Tubular Bells and Penn State fields in the Gulf of Mexico based on drilling plans for new wells.

*2014:* In the United States, we recognized additions of 97 million boe in the Bakken shale play and 18 million boe in the Utica shale play based on drilling plans for new wells. We also recognized 21 million boe related to the sanction of the Stampede development project in the Gulf of Mexico. At the Valhall Field in Norway, additions resulting from planned drilling activity were 37 million boe. At the North Malay Basin, we recognized additions of 186 million mcf of natural gas upon signing a gas sales agreement for the full field development phase of the project.

*2013:* In the United States, we recognized additions of 192 million boe in the Bakken shale play as a result of additional planned development activities.

*Revisions of previous estimates – Price Revisions*

*2015:* Negative revisions to proved undeveloped reserves at December 31, 2015, resulting from lower commodity prices were 220 million boe (consisting of 147 million barrels of crude oil, 22 million barrels of natural gas liquids and 303 million mcf of natural gas). The negative revisions recognized were primarily in the Bakken shale play (127 million boe), North Malay Basin in Malaysia (34 million boe), the Valhall Field in Norway (30 million boe) and the Stampede project in the Gulf of Mexico (21 million boe).

*Revisions of previous estimates – Technical Revisions*

*2015:* In the United States, negative technical revisions include 48 million boe related to planned drilling dates of certain Bakken wells moving beyond 2020 due to reprioritization of the drilling schedule. At the Valhall Field in Norway, downward technical revisions of 26 million boe primarily resulted from drilling schedule changes.

*2014:* In the United States, Bakken downward technical revisions of 47 million boe (consisting of 40 million barrels of crude oil and 7 million barrels of natural gas liquids) were as a result of well performance and reprioritization of well locations in the drilling schedule resulting in certain wells moving beyond 2019. At the Valhall Field in Norway, downward technical revisions amounted to 9 million boe.

*2013:* In the United States, negative technical revisions include 43 million boe related to the Bakken.

*Transfers to proved developed reserves ('Transfers')*

*2015:* Transfers from proved undeveloped reserves to proved developed reserves included 43 million boe in the Bakken shale play, 61 million boe at the JDA gas field in the Gulf of Thailand, and 11 million boe at the Valhall Field in Norway.

*2014:* Transfers from proved undeveloped reserves into proved developed reserves included 38 million boe in the Bakken shale play, 30 million boe related to the Tubular Bells Field in the Gulf of Mexico as a result of first production in 2014, and 15 million boe at the Valhall Field in Norway.

*2013:* Transfers from proved undeveloped reserves into proved developed reserves primarily related to 36 million boe from the Bakken shale play and 21 million related to the Valhall Field in Norway as a result of continuing development activity and new wells.

In 2015, capital expenditures of $1,931 million were incurred to convert proved undeveloped reserves to proved developed reserves (2014: $3,110 million; 2013: $1,765 million). Capital expenditures in 2014 include production facilities and subsea infrastructure for the Tubular Bells field in the Gulf of Mexico which achieved first production in late 2014.

We are also involved in multiple long-term projects that have staged developments. Certain of these projects have proved reserves, which have been classified as undeveloped for a period in excess of five years, totaling 45 million boe or 4% of total proved reserves at December 31, 2015. Most of the proved undeveloped reserves in excess of five years relate to the Valhall Field in Norway.

**Production Sharing Contracts**

The Corporation's proved reserves include crude oil and natural gas reserves relating to long-term agreements with governments or authorities in which the Corporation has the legal right to produce or has a revenue interest in the production. Proved reserves from these production sharing contracts for each of the three years ended December 31, 2015 are presented separately below, as well as volumes produced and received during 2015, 2014 and 2013 from these production sharing contracts.

| | Crude Oil, Condensate & Natural Gas Liquids | | | | | Natural Gas | | | |
|---|---|---|---|---|---|---|---|---|---|
| | United States | Europe | Africa | Asia | Total | United States | Europe | Asia and Africa | Total |
| | (Millions of barrels) | | | | | (Millions of mcf) | | | |
| **Production Sharing Contracts** | | | | | | | | | |
| **Proved Reserves (a)** | | | | | | | | | |
| At December 31, 2013 | — | — | 57 | 18 | 75 | — | — | 914 | 914 |
| At December 31, 2014 | — | — | 52 | 7 | 59 | — | — | 913 | 913 |
| At December 31, 2015 | **—** | **—** | **34** | **5** | **39** | **—** | **—** | **687** | **687** |
| **Production** | | | | | | | | | |
| 2013 | — | — | 18 | 3 | 21 | — | — | 122 | 122 |
| 2014 | — | — | 18 | 1 | 19 | — | — | 107 | 107 |
| 2015 | **—** | **—** | **18** | **1** | **19** | **—** | **—** | **108** | **108** |

*(a) Includes natural gas liquids of - million barrels in 2015 (2014: - million; 2013: 3 million).*

**<u>Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves</u>**

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

The selling prices of crude oil and natural gas are highly volatile. The prices required to be used for the discounted future net cash flows are on the same basis for determining proved oil and gas reserves and do not include the effects of commodity hedges. As a result, selling prices used in the disclosure of future net cash flows may not be representative of future selling prices. In addition, the discounted future net cash flow estimates do not include exploration expenses, interest expense or corporate general and administrative expenses. The amount of tax deductions, credits, and allowances relating to the Corporation's proved oil and gas reserves can change year to year due to factors including changes in proved reserves, variances in actual pre-tax cash flows from forecasted pre-tax cash flows in historical periods, and the impact to year-end carryforward tax attributes associated with deducting in the Corporation's income tax returns exploration expenses, interest expense, and corporate general and administrative expenses that are not contemplated in the standardized measure computations. The future net cash flow estimates could be materially different if other assumptions were used.

| At December 31 | Total | United States | Europe (a) | Africa | Asia |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| **2015** | | | | | |
| Future revenues | **$ 41,010** | **$ 15,257** | **$ 13,456** | **$ 9,419** | **$ 2,878** |
| Less: | | | | | |
| Future production costs | **14,275** | **6,775** | **5,000** | **1,628** | **872** |
| Future development costs | **8,486** | **2,901** | **4,088** | **1,150** | **347** |
| Future income tax expenses | **7,237** | **-** | **1,022** | **6,089** | **126** |
| | **29,998** | **9,676** | **10,110** | **8,867** | **1,345** |
| Future net cash flows | **11,012** | **5,581** | **3,346** | **552** | **1,533** |
| Less: Discount at 10% annual rate | **3,822** | **1,826** | **1,469** | **114** | **413** |
| Standardized measure of discounted future net cash flows | **$ 7,190** | **$ 3,755** | **$ 1,877** | **$ 438** | **$ 1,120** |
| 2014 | | | | | |
| Future revenues | $ 107,949 | $ 51,054 | $ 31,150 | $ 19,448 | $ 6,297 |
| Less: | | | | | |
| Future production costs | 27,790 | 14,553 | 9,116 | 2,743 | 1,378 |
| Future development costs | 21,393 | 10,150 | 7,930 | 1,244 | 2,069 |
| Future income tax expenses | 27,060 | 6,798 | 7,143 | 12,876 | 243 |
| | 76,243 | 31,501 | 24,189 | 16,863 | 3,690 |
| Future net cash flows | 31,706 | 19,553 | 6,961 | 2,585 | 2,607 |
| Less: Discount at 10% annual rate | 14,704 | 9,988 | 3,251 | 393 | 1,072 |
| Standardized measure of discounted future net cash flows | $ 17,002 | $ 9,565 | $ 3,710 | $ 2,192 | $ 1,535 |
| 2013 | | | | | |
| Future revenues | $ 115,826 | $ 49,370 | $ 33,705 | $ 23,404 | $ 9,347 |
| Less: | | | | | |
| Future production costs | 32,112 | 14,877 | 12,506 | 3,034 | 1,695 |
| Future development costs | 19,985 | 8,826 | 8,080 | 1,466 | 1,613 |
| Future income tax expenses | 30,427 | 7,281 | 6,088 | 15,491 | 1,567 |
| | 82,524 | 30,984 | 26,674 | 19,991 | 4,875 |
| Future net cash flows | 33,302 | 18,386 | 7,031 | 3,413 | 4,472 |
| Less: Discount at 10% annual rate | 12,842 | 7,708 | 3,134 | 704 | 1,296 |
| Standardized measure of discounted future net cash flows | $ 20,460 | $ 10,678 | $ 3,897 | $ 2,709 | $ 3,176 |

*(a) At December 31, the standardized measure of discounted future net cash flows relating to proved reserves in Norway were as follows:*

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| | | *(In millions)* | |
| *Future revenues* | *$ 11,639* | *$ 27,502* | *$ 29,668* |
| *Less:* | | | |
| *Future production costs* | *4,404* | *8,159* | *11,538* |
| *Future development costs* | *3,653* | *7,318* | *7,226* |
| *Future income tax expenses* | *903* | *6,683* | *5,567* |
| | *8,960* | *22,160* | *24,331* |
| *Future net cash flows* | *2,679* | *5,342* | *5,337* |
| *Less: Discount at 10% annual rate* | *1,332* | *2,792* | *2,483* |
| *Standardized measure of discounted future net cash flows* | *$ 1,347* | *$ 2,550* | *$ 2,854* |

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

| **For the Years Ended December 31** | **2015** | **2014** | **2013** |
|---|---|---|---|
| | | **(In millions)** | |
| Standardized measure of discounted future net cash flows at January 1 | **$ 17,002** | $ 20,460 | $ 23,232 |
| Changes during the year | | | |
| Sales and transfers of oil and gas produced during the year, net of production costs | **(2,842)** | (6,537) | (7,677) |
| Development costs incurred during year | **3,398** | 4,401 | 4,516 |
| Net changes in prices and production costs applicable to future production | **(20,236)** | (4,657) | (2,847) |
| Net change in estimated future development costs | **5,116** | (485) | (2,798) |
| Extensions and discoveries (including improved recovery) of oil and gas reserves, less related costs | **530** | 2,249 | 3,836 |
| Revisions of previous oil and gas reserve estimates | **(1,274)** | (161) | (1,189) |
| Net purchases (sales) of minerals in place, before income taxes | **(18)** | (2,157) | (3,905) |
| Accretion of discount | **2,799** | 3,243 | 4,038 |
| Net change in income taxes | **7,601** | 3,180 | 6,191 |
| Revision in rate or timing of future production and other changes | **(4,886)** | (2,534) | (2,937) |
| Total | **(9,812)** | (3,458) | (2,772) |
| Standardized measure of discounted future net cash flows at December 31 | **$ 7,190** | $ 17,002 | $ 20,460 |

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

Following are quarterly results of operations:

| | 2015 | | | |
|---|---|---|---|---|
| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
| | (In millions, except per share amounts) | | | |
| Sales and other operating revenues | $ 1,538 | $ 1,953 | $ 1,671 | $ 1,474 |
| Gross profit (loss) from continuing operations (a) | $ (238) | $ (364) | $ (210) | $ (1,592) |
| Income (loss) from continuing operations | $ (376) | $ (553) | $ (239) | $ (1,791) |
| Income (loss) from discontinued operations | (13) | (14) | (13) | (8) |
| Net income (loss) | (389) | (567) | (252) | (1,799) |
| Less: Net income (loss) attributable to noncontrolling interests | — | — | 27 | 22 |
| Net income (loss) attributable to Hess Corporation | $ (389)(b) | $ (567)(c) | $ (279)(d) | $ (1,821)(e) |
| Net income (loss) attributable to Hess Corporation per share: | | | | |
| Basic: | | | | |
| Continuing operations | $ (1.32) | $ (1.94) | $ (0.94) | $ (6.40) |
| Discontinued operations | (0.05) | (0.05) | (0.04) | (0.03) |
| Net income (loss) per share | $ (1.37) | $ (1.99) | $ (0.98) | $ (6.43) |
| Diluted: | | | | |
| Continuing operations | $ (1.32) | $ (1.94) | $ (0.94) | $ (6.40) |
| Discontinued operations | (0.05) | (0.05) | (0.04) | (0.03) |
| Net income (loss) per share | $ (1.37) | $ (1.99) | $ (0.98) | $ (6.43) |

| | 2014 | | | |
|---|---|---|---|---|
| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
| | (In millions, except per share amounts) | | | |
| Sales and other operating revenues | $ 2,673 | $ 2,829 | $ 2,678 | $ 2,557 |
| Gross profit (loss) from continuing operations (a) | $ 1,026 | $ 1,000 | $ 837 | $ 622 |
| Income (loss) from continuing operations | $ 364 | $ 974 | $ 359 | $ (5) |
| Income (loss) from discontinued operations | 57 | (44) | 671 | (2) |
| Net income (loss) | 421 | 930 | 1,030 | (7) |
| Less: Net income (loss) attributable to noncontrolling interests | 35 | (1) | 22 | 1 |
| Net income (loss) attributable to Hess Corporation | $ 386(f) | $ 931(g) | $ 1,008(h) | $ (8)(i) |
| Net income (loss) attributable to Hess Corporation per share: | | | | |
| Basic: | | | | |
| Continuing operations | $ 1.14 | $ 3.15 | $ 1.19 | $ (0.02) |
| Discontinued operations | 0.07 | (0.14) | 2.16 | (0.01) |
| Net income (loss) per share | $ 1.21 | $ 3.01 | $ 3.35 | $ (0.03) |
| Diluted: | | | | |
| Continuing operations | $ 1.13 | $ 3.10 | $ 1.18 | $ (0.02) |
| Discontinued operations | 0.07 | (0.14) | 2.13 | (0.01) |
| Net income (loss) per share | $ 1.20 | $ 2.96 | $ 3.31 | $ (0.03) |

(a) *Gross profit represents Sales and other operating revenues, less Cost of products sold, Operating costs and expenses, Production and severance taxes, Depreciation, depletion and amortization and Impairments.*
(b) *Includes after-tax charges of $77 million related to dry hole and related expenses and an after-tax charge of $16 million for inventory write-offs.*
(c) *Includes a non-taxable charge of $385 million related to goodwill impairment associated with our onshore E&P business and an after-tax charge of $21 million related to terminated international office space.*
(d) *Includes an after-tax gain of $31 million from the sale of Utica dry gas acreage, $50 million tax benefit associated with an international investment incentive, and an after-tax charge of $43 million of dry hole, lease impairment and other exploration expenses.*
(e) *Includes a non-taxable charge of $1,098 million related to goodwill impairment associated with our offshore E&P business, exploration charges of $178 million primarily related to previously capitalized well costs and net after-tax impairment charge of $83 million associated with our legacy conventional assets in North Dakota. In addition, we recorded an after-tax charge of $41 million for our estimated liability resulting from HOVENSA LLC's bankruptcy settlement.*
(f) *Includes after-tax charge of $52 million to reduce carrying value of its investments in Bayonne Energy Center asset sales to fair value and $48 million after-tax charge relating to severance and other exits costs partially offset by $40 million after-tax gain on sale of assets and liquidation of LIFO inventories.*
(g) *Includes after-tax gain of $765 million related to an asset sale and liquidation of LIFO inventories, partially offset by after-tax charges totaling $266 million for dry hole expenses, asset impairment, employee severance and other exit costs.*

*(h) Includes an after-tax gain of $749 million relating to asset sales and liquidation of LIFO inventories, partially offset by after-tax charges totaling $118 million related to environmental, impairment, severance and exit related costs.*
*(i) Includes after-tax charge of $48 million for remeasurement of deferred taxes resulting from legal entity restructurings and $13 million after-tax charges related to severance, exit costs and other charges.*

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

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

None.

## Item 9A. Controls and Procedures

Based upon their evaluation of the Corporation’s disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of December 31, 2015, John B. Hess, Chief Executive Officer, and John P. Rielly, Chief Financial Officer, concluded that these disclosure controls and procedures were effective as of December 31, 2015.

There was no change in internal controls over financial reporting identified in the evaluation required by paragraph (d) of Rules 13a-15 or 15d-15 in the quarter ended December 31, 2015 that has materially affected, or is reasonably likely to materially affect, internal controls over financial reporting.

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

## Item 9B. Other Information

None.

# PART III

## Item 10. Directors, Executive Officers and Corporate Governance

Information relating to Directors is incorporated herein by reference to “Election of Directors” from the Registrant’s definitive proxy statement for the 2016 annual meeting of stockholders.

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

Information relating to the audit committee is incorporated herein by reference to “Election of Directors” from the registrant’s definitive proxy statement for the 2016 annual meeting of stockholders.

**Executive Officers of the Registrant**

The following table presents information as of February 25, 2016 regarding executive officers of the Registrant:

| Name | Age | Office Held* and Business Experience | Year Individual Became an Executive Officer |
|---|---|---|---|
| John B. Hess | 61 | Chief Executive Officer and Director<br>Mr. Hess has been Chief Executive Officer of the Registrant since 1995 and employed by the Registrant since 1977. He has over 37 years of experience in the oil and gas industry. | 1983 |
| Gregory P. Hill | 54 | Chief Operating Officer, Executive Vice President and President, Exploration and Production<br>Mr. Hill has been Chief Operating Officer since 2014. Mr. Hill has been President of Registrant's worldwide exploration and production business since joining the Registrant in January 2009. Prior to joining the Registrant, Mr. Hill spend 25 years at Royal Dutch Shell and its affiliates in a variety of operations, engineering, technical and managerial roles in Asia-Pacific, Europe and the United States. | 2009 |
| Timothy B. Goodell | 58 | Senior Vice President and General Counsel<br>Mr. Goodell has been the Senior Vice President and General Counsel of the Registrant since 2009. Prior to joining the Registrant in 2009, he was a partner at the law firm of White & Case, LLP where he spent 25 years. | 2009 |
| John P. Rielly | 53 | Senior Vice President and Chief Financial Officer<br>Mr. Rielly has been the Senior Vice President and Chief Financial Officer of the Registrant since 2004. Mr. Rielly previously served as Vice President and Controller of the Registrant from 2001 to 2004. Prior to joining the Registrant in 2001, he was a Partner at Ernst & Young, LLP where he was employed for 16 years. | 2002 |
| Brian D. Truelove | 57 | Senior Vice President, Offshore<br>Mr. Truelove has been Senior Vice President, Offshore of the Registrant since 2013. He previously served as Senior Vice President, Services. Prior to joining the Registrant in 2011, Mr. Truelove spent 30 years with Royal Dutch Shell and its affiliates, where he served in a variety of managerial and operating roles around the world. | 2014 |
| Michael R. Turner | 56 | Senior Vice President, Onshore<br>Mr. Turner has been Senior Vice President, Onshore of the Registrant since 2013. He previously served as Senior Vice President, Global Production. Prior to joining the Registrant in 2009, Mr. Turner spent 28 years with Royal Dutch Shell and its affiliates in a variety of production leadership positions around the world. | 2014 |
| Barbara Lowery-Yilmaz | 59 | Senior Vice President, Exploration<br>Ms. Lowery-Yilmaz has been the Senior Vice President, Exploration of the Registrant since August 2014. Ms. Lowery-Yilmaz has over 30 years of oil and gas industry experience in exploration and technology with BP plc and its affiliates including senior leadership roles. | 2014 |
| Mykel J. Ziolo | 63 | Senior Vice President, Human Resources<br>Mr. Ziolo has been Senior Vice President, Human Resources of the Registrant since 2009. He has a 38-year career in human resources working in the United States and internationally. Mr. Ziolo previously served as Global Head and Vice President, Human Resources – worldwide exploration and production of the Registrant. Prior to joining the Registrant in 2002, Mr. Ziolo served in several human resource positions in the energy industry, including 15 years with BHP Billiton. | 2009 |

* *All officers referred to herein hold office in accordance with the By-laws until the first meeting of the Directors following the annual meeting of stockholders of the Registrant and until their successors shall have been duly chosen and qualified. Each of said officers was elected to the office opposite his name on May 6, 2015.*

Except for Mr. Truelove and Ms. Lowery-Yilmaz, each of the above officers has been employed by the Registrant or its affiliates in various managerial and executive capacities for more than five years. Prior to joining the Registrant, Mr. Truelove and Ms. Lowery-Yilmaz served in senior executive positions in exploration and production at Royal Dutch Shell and its affiliates and BP plc and its affiliates, respectively.

**Item 11. Executive Compensation**

Information relating to executive compensation is incorporated herein by reference to "Election of Directors—Executive Compensation and Other Information," from the Registrant's definitive proxy statement for the 2016 annual meeting of stockholders.

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

Information pertaining to security ownership of certain beneficial owners and management is incorporated herein by reference to "Election of Directors—Ownership of Voting Securities by Certain Beneficial Owners" and "Election of Directors—Ownership of Equity Securities by Management" from the Registrant's definitive proxy statement for the 2016 annual meeting of stockholders.

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

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

Information relating to this item is incorporated herein by reference to "Election of Directors" from the Registrant's definitive proxy statement for the 2016 annual meeting of stockholders.

**Item 14. Principal Accounting Fees and Services**

Information relating to this item is incorporated by reference to "Ratification of Selection of Independent Auditors" from the Registrant's definitive proxy statement for the 2016 annual meeting of stockholders.

# PART IV

## Item 15. Exhibits, Financial Statement Schedules

### (a) 1. and 2. Financial statements and financial statement schedules

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

### 3. Exhibits

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

## SIGNATURES

**Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 25th day of February 2016.**

HESS CORPORATION
**(Registrant)**

By /s/ JOHN P. RIELLY
**(John P. Rielly)**
**Senior Vice President and**
**Chief Financial Officer**

**Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.**

| Signature | Title | Date |
|---|---|---|
| /s/ JOHN B. HESS<br>**John B. Hess** | Director and<br>Chief Executive Officer<br>(Principal Executive Officer) | February 25, 2016 |
| /s/ DR. MARK R. WILLIAMS<br>**Dr. Mark R. Williams** | Director and<br>Chairman of the Board | February 25, 2016 |
| /s/ RODNEY F. CHASE<br>**Rodney F. Chase** | Director | February 25, 2016 |
| /s/ TERRENCE J. CHECKI<br>**Terrence J. Checki** | Director | February 25, 2016 |
| /s/ HARVEY GOLUB<br>**Harvey Golub** | Director | February 25, 2016 |
| /s/ EDITH E. HOLIDAY<br>**Edith E. Holiday** | Director | February 25, 2016 |
| /s/ DR. RISA LAVIZZO-MOUREY<br>**Dr. Risa Lavizzo-Mourey** | Director | February 25, 2016 |
| /s/ DAVID MCMANUS<br>**David McManus** | Director | February 25, 2016 |
| /s/ DR. KEVIN O. MEYERS<br>**Dr. Kevin O. Meyers** | Director | February 25, 2016 |
| /s/ JOHN H. MULLIN, III<br>**John H. Mullin, III** | Director | February 25, 2016 |
| /s/ JAMES H. QUIGLEY<br>**James H. Quigley** | Director | February 25, 2016 |
| /s/ FREDRIC G. REYNOLDS<br>**Fredric G. Reynolds** | Director | February 25, 2016 |
| /s/ JOHN P. RIELLY<br>**John P. Rielly** | Senior Vice President and Chief<br>Financial Officer<br>(Principal Financial and Accounting Officer) | February 25, 2016 |
| /s/ WILLIAM G. SCHRADER<br>**William G. Schrader** | Director | February 25, 2016 |
| /s/ ROBERT N. WILSON<br>**Robert N. Wilson** | Director | February 25, 2016 |

**HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES**

**VALUATION AND QUALIFYING ACCOUNTS**

**For the Years Ended December 31, 2015, 2014 and 2013**

| Description | Balance January 1 | Additions: Charged to Costs and Expenses | Additions: Charged to Other Accounts | Deductions from Reserves | Balance December 31 |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| **2015** | | | | | |
| Losses on receivables | **$ 13** | **$ 32** | **$ —** | **$ 2** | **$ 43** |
| Deferred income tax valuation | **$ 1,416** | **$ 280** | **$ —** | **$ 118** | **$ 1,578** |
| **2014** | | | | | |
| Losses on receivables | $ 27 | $ — | $ — | $ 14 | $ 13 |
| Deferred income tax valuation | $ 1,519 | $ 142 | $ (1) | $ 244 | $ 1,416 |
| **2013** | | | | | |
| Losses on receivables | $ 34 | $ 10 | $ — | $ 17 | $ 27 |
| Deferred income tax valuation | $ 1,282 | $ 383 | $ (17) | $ 129 | $ 1,519 |

## EXHIBIT INDEX

| | |
|---|---|
| 3(1) | Restated Certificate of Incorporation of Registrant, including amendment thereto dated May 3, 2006 incorporated by reference to Exhibit 3 of Registrant's Form 10-Q for the three months ended June 30, 2006. |
| 3(2) | Certificate of Amendment to the Restated Certificate of Incorporation of Registrant, dated May 22, 2013, incorporated by reference to Exhibit 3(1) of Form 8-K of Registrant filed on May 22, 2013. |
| 3(3) | Certificate of Amendment to the Restated Certificate of Incorporation of Registrant, effective May 12, 2014, incorporated by reference to Exhibit 3(1) of Form 8-K of Registrant filed on May 13, 2014. |
| 3(4) | Certificate of Designations of the 8.00% Series A Mandatory Convertible Preferred Stock of Hess Corporation, including Form of Certificate for the 8.00% Series A Mandatory Convertible Preferred Stock incorporated by reference to Exhibit 3(1) of Form 8-K of Registrant filed on February 10, 2016. |
| 3(5) | By-laws of Registrant incorporated by reference to Exhibit 3(2) of Form 8-K of Registrant filed on November 9, 2015. |
| 4(1) | Five-Year Credit Agreement, dated as of January 21, 2015, among Registrant, certain subsidiaries of Registrant, J.P. Morgan Chase Bank, N.A. as lender and administrative agent, and the other lenders party thereto, incorporated by reference to Exhibit 10(1) of Form 8-K of Registrant filed on January 27, 2015. |
| 4(2) | Amendment No. 1 to the Five-Year Credit Agreement, dated as of July 10, 2015 among Hess Corporation, the subsidiaries party thereto, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent, incorporated by reference to Exhibit 10(2) of Form 10-Q of Registrant for the three months ended June 30, 2015. |
| 4(3) | Indenture dated as of October 1, 1999, between Registrant and The Chase Manhattan Bank, as Trustee, incorporated by reference to Exhibit 4(1) of Form 10-Q of Registrant for the three months ended September 30, 1999. |
| 4(4) | First Supplemental Indenture, dated as of October 1, 1999, between Registrant and The Chase Manhattan Bank, as Trustee, relating to Registrant's $7^3/_8$% Notes due 2009 and $7^7/_8$% Notes due 2029, incorporated by reference to Exhibit 4(2) of Form 10-Q of Registrant for the three months ended September 30, 1999. |
| 4(5) | Prospectus Supplement, dated August 8, 2001, to Prospectus dated July 27, 2001 relating to Registrant's 5.30% Notes due 2004, 5.90% Notes due 2006, 6.65% Notes due 2011 and 7.30% Notes due 2031, incorporated by reference to Registrant's prospectus filed pursuant to Rule 424(b)(2) under the Securities Act of 1933, as amended, on August 9, 2001. |
| 4(6) | Prospectus Supplement, dated February 28, 2002, to Prospectus dated July 27, 2001 relating to Registrant's 7.125% Notes due 2033, incorporated by reference to Registrant's prospectus filed pursuant to Rule 424(b)(4) under the Securities Act of 1933, as amended, on March 1, 2002. |
| 4(7) | Indenture dated as of March 1, 2006, between Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase Bank, N.A., as Trustee, including form of Note, incorporated by reference to Exhibit 4 to Registrant's Form S-3ASR filed on March 1, 2006. |
| 4(8) | Form of 8.125% Note due 2019, incorporated by reference to Exhibit 4(2) to Form 8-K of the Registrant, filed on February 4, 2009. |
| 4(9) | Form of 6.00% Note due 2040, incorporated by reference to Exhibit 4(1) to Form 8-K of Registrant filed on December 15, 2009. |
| 4(10) | Form of 5.60% Note due 2041, incorporated by reference to Exhibit 4(1) to Form 8-K of Registrant filed on August 12, 2010. |
| 4(11) | Form of 1.30% Note due 2017, incorporated by reference to Exhibit 4(2) to Form 8-K of Registrant filed on June 25, 2014. |
| 4(12) | Form of 3.50% Note due 2024, incorporated by reference to Exhibit 4(3) to Form 8-K of Registrant filed on June 25, 2014. |

| | |
|---|---|
| 4(13) | Deposit Agreement, dated as of February 10, 2016, among Hess Corporation and Computershare Inc. and Computershare Trust Company, N.A., as depositary, on behalf of all holders from time to time of the receipts issued thereunder, including Form of Depositary Receipt for the Depositary Shares incorporated by reference to Exhibit 4(2) of Form 8-K of Registrant filed on February 10, 2016.<br>Other instruments defining the rights of holders of long-term debt of Registrant and its consolidated subsidiaries are not being filed since the total amount of securities authorized under each such instrument does not exceed 10 percent of the total assets of Registrant and its subsidiaries on a consolidated basis. Registrant agrees to furnish to the Securities and Exchange Commission a copy of any instruments defining the rights of holders of long-term debt of Registrant and its subsidiaries upon request. |
| 10(1)* | Annual Cash Incentive Plan description incorporated by reference to Item 5.02 of Form 8-K of Registrant filed on March 9, 2015. |
| 10(2)* | Financial Counseling Program description incorporated by reference to Exhibit 10(6) of Form 10-K of Registrant for the fiscal year ended December 31, 2004. |
| 10(3)* | Hess Corporation Savings and Stock Bonus Plan incorporated by reference to Exhibit 10(7) of Form 10-K of Registrant for the fiscal year ended December 31, 2006. |
| 10(4)* | Performance Incentive Plan for Senior Officers, as amended, as approved by stockholders on May 4, 2011, incorporated by reference to Annex A to the definitive proxy statement of Registrant filed on March 25, 2011. |
| 10(5)* | Hess Corporation Pension Restoration Plan, dated January 19, 1990, incorporated by reference to Exhibit 10(9) of Form 10-K of Registrant for the fiscal year ended December 31, 1989. |
| 10(6)* | Amendment, dated December 31, 2006, to Hess Corporation Pension Restoration Plan, incorporated by reference to Exhibit 10(10) of Form 10-K of Registrant for the fiscal year ended December 31, 2006. |
| 10(7)* | Letter Agreement, dated May 17, 2001, between Registrant and John P. Rielly relating to Mr. Rielly's participation in the Hess Corporation Pension Restoration Plan, incorporated by reference to Exhibit 10(18) of Form 10-K of Registrant for the fiscal year ended December 31, 2002. |
| 10(8)* | Second Amended and Restated 1995 Long-term Incentive Plan, including forms of awards thereunder, incorporated by reference to Exhibit 10(11) of Form 10-K of Registrant for the fiscal year ended December 31, 2004. |
| 10(9)* | Amended and Restated 2008 Long-term Incentive Plan, incorporated by reference to Form 8-K of the Registrant filed on May 12, 2015. |
| 10(10)* | Forms of Awards under Registrant's 2008 Long-term Incentive Plan, incorporated by reference to Exhibit 10(14) of Form 10-K of Registrant for the fiscal year ended December 31, 2009. |
| 10(11)* | Form of Performance Award Agreement under Registrant's 2008 Long-term Incentive Plan incorporated by reference to Exhibit 10(2) of Form 8-K of Registrant filed on March 13, 2012. |
| 10(12)* | Form of Restricted Stock Award Agreement under Registrant's Amended and Restated 2008 Long-term Incentive Plan, incorporated by reference to Exhibit 10(2) of Form 10-Q of Registrant for the three months ended March 31, 2015. |
| 10(13)* | Form of Performance Award Agreement for the three-year period ending December 31, 2016 under Registrant's 2008 Long-term Incentive Plan, incorporated by reference to Exhibit 10(1) of Form 10-Q of Registrant for the three months ended March 31, 2014. |
| 10(14)* | Form of Performance Award Agreement for the three-year period ending December 31, 2017 under Registrant's Amended and Restated 2008 Long-term Incentive Plan, incorporated by reference to Exhibit 10(3) of Form 10-Q of Registrant for the three months ended March 31, 2015. |
| 10(15)* | Compensation program description for non-employee directors, incorporated by reference to Item 1.01 of Form 8-K of Registrant filed on January 4, 2007. |
| 10(16)* | Form of Amended and Restated Change of Control Termination Benefits Agreement, dated as of May 29, 2009, incorporated by reference to Exhibit 10(1) of Form 10-Q of Registrant for the three months ended June 30, 2009. A substantially identical agreement (differing only in the signatories thereto) was entered into between Registrant and John B. Hess. |

| | |
|---|---|
| 10(17)* | Amended and Restated Change of Control Termination Benefits Agreement, dated as of May 29, 2009, between Registrant and John P. Rielly, incorporated by reference to Exhibit 10(17) of Form 10-K of Registrant for the fiscal year ended December 31, 2009. Substantially identical agreements (differing only in the signatories thereto) were entered into between Registrant and other executive officers (including the named executive officers, other than Michael Turner and John B.Hess). |
| 10(18) | Form of Change in Control Termination Benefits Agreement, dated as of August 3, 2015, between the Registrant and Michael R. Turner, incorporated by reference to Exhibit 10(3) of Form 10-Q of Registrant for the three months ended June 30, 2015. Substantially identical agreements (differing only in the signatories thereto) were entered into between the Registrant and four other senior officers. |
| 10(19)* | Agreement between Registrant and Gregory P. Hill, relating to Mr. Hill's compensation and other terms of employment, incorporated by reference to Item 5.02 of Form 8-K of Registrant filed January 7, 2009. |
| 10(20)* | Agreement between Registrant and Timothy B. Goodell, relating to Mr. Goodell's compensation and other terms of employment, incorporated by reference to Exhibit 10(20) of Registrant's Form 10-K for the fiscal year ended December 31, 2009. |
| 10(21)* | Deferred Compensation Plan of Registrant, dated December 1, 1999, incorporated by reference to Exhibit 10(16) of Form 10-K of Registrant for the fiscal year ended December 31, 1999. |
| 10(22) | Agreement, dated as of May 16, 2013, among Registrant, Elliott Associates, L.P. and Elliott International, L.P., incorporated by reference to Exhibit 99(1) of Form 8-K of Registrant filed on May 22, 2013. |
| 21 | Subsidiaries of Registrant. |
| 23(1) | Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm, dated February 25, 2016. |
| 23(2) | Consent of DeGolyer and MacNaughton dated February 25, 2016. |
| 31(1) | Certification required by Rule 13a-14(a) (17 CFR 240.13a-14(a)) or Rule 15d-14(a) (17 CFR 240.15d-14(a)). |
| 31(2) | Certification required by Rule 13a-14(a) (17 CFR 240.13a-14(a)) or Rule 15d-14(a) (17 CFR 240.15d-14(a)). |
| 32(1) | Certification required by Rule 13a-14(b) (17 CFR 240.13a-14(b)) or Rule 15d-14(b) (17 CFR 240.15d-14(b)) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350). |
| 32(2) | Certification required by Rule 13a-14(b) (17 CFR 240.13a-14(b)) or Rule 15d-14(b) (17 CFR 240.15d-14(b)) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350). |
| 99(1) | Letter report of DeGolyer and MacNaughton, Independent Petroleum Engineering Consulting Firm, dated February 3, 2016, on proved reserves audit as of December 31, 2015 of certain properties attributable to Registrant. |
| 101(INS) | XBRL Instance Document |
| 101(SCH) | XBRL Schema Document |
| 101(CAL) | XBRL Calculation Linkbase Document |
| 101(LAB) | XBRL Labels Linkbase Document |
| 101(PRE) | XBRL Presentation Linkbase Document |
| 101(DEF) | XBRL Definition Linkbase Document |

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

# HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

## SUBSIDIARIES OF THE REGISTRANT

| Name of Company | Jurisdiction |
|---|---|
| Hess Bakken Investments II L.L.C. | Delaware |
| Hess Capital Holdings Limited | Cayman Islands |
| Hess Capital Limited | Cayman Islands |
| Hess Capital Services Corporation | Delaware |
| Hess Capital Services L.L.C. | Delaware |
| Hess Conger LLC | Delaware |
| Hess Denmark Aps | Denmark |
| Hess Exploration and Production Malaysia B.V | The Netherlands |
| Hess Exploration Australia PTY Limited | Australia |
| Hess Energy Exploration Limited | Delaware |
| Hess Equatorial Guinea Inc. | Cayman Islands |
| Hess Exploration & Production Holdings Limited | Delaware |
| Hess (Ghana) Limited | Cayman Islands |
| Hess GOM Exploration L.L.C | Delaware |
| Hess Gulf of Mexico Ventures L.L.C. | Delaware |
| Hess International Holdings Corporation | Delaware |
| Hess Middle East New Ventures Limited | Cayman Islands |
| Hess (Netherlands) Oil & Gas Holdings C.V. | The Netherlands |
| Hess Norge AS | Norway |
| Hess North Dakota Pipelines L.L.C | Cayman Islands |
| Hess Norway LP | Cayman Islands |
| Hess Ohio Developments, L.L.C | Delaware |
| Hess Ohio Sub-Holdings L.L.C | Delaware |
| Hess Oil and Gas Holdings Inc. | Cayman Islands |
| Hess Oil Company Of Thailand (JDA) Limited | Cayman Islands |
| Hess Shenzi L.L.C | Delaware |
| Hess Stampede L.L.C | Delaware |
| Hess Tioga Gas Plant L.L.C | Delaware |
| Hess Trading Corporation | Delaware |
| Hess Tubular L.L.C | Delaware |
| Hess West Africa Holdings Limited | Cayman Islands |

Other subsidiaries (names omitted because such unnamed subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary).

Each of the foregoing subsidiaries conducts business under the name listed, and is 100% owned by the Registrant.

**Exhibit 23(1)**

**Consent of Independent Registered Public Accounting Firm**

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

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

(2) Registration Statement (Form S-8 No. 333-94851) pertaining to the Hess Corporation Amended and Restated 1995 Long-term Incentive Plan,

(3) Registration Statement (Form S-8 No. 333-115844) pertaining to the Hess Corporation Second Amended and Restated 1995 Long-term Incentive Plan,

(4) Registration Statement (Form S-8 No. 333-150992) pertaining to the Hess Corporation 2008 Long-term Incentive Plan,

(5) Registration Statement (Form S-8 No. 333-167076) pertaining to the Hess Corporation 2008 Long-term Incentive Plan,

(6) Registration Statement (Form S-8 No. 333-181704) pertaining to the Hess Corporation 2008 Long-term Incentive Plan, and

(7) Registration Statement (Form S-8 No. 333-204929) pertaining to the Hess Corporation 2008 Long-term Incentive Plan, and

(8) Registration Statement (Form S-3 No. 333-202379) of Hess Corporation;

of our reports dated February 25, 2016, with respect to the consolidated financial statements and schedule of Hess Corporation and the effectiveness of internal control over financial reporting of Hess Corporation included in this Annual Report (Form 10-K) of Hess Corporation for the year ended December 31, 2015.

/s/ Ernst & Young LLP
New York, New York
February 25, 2016

**Exhibit 23(2)**

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

February 25, 2016

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

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton as an independent petroleum engineering consulting firm, to references to our third-party letter report dated February 3, 2016, containing our opinion on the proved reserves attributable to certain properties owned by Hess Corporation, as of December 31, 2015, (our "Report"), under the heading "Oil and Gas Reserves-Reserves Audit," and to the inclusion of our Report as an exhibit in Hess Corporation's Annual Report on Form 10-K for the year ended December 31, 2015. We also consent to all such references, including under the heading "Experts," and to the incorporation by reference of our Report in the Registration Statements filed by Hess Corporation on Form S-3 (No. 333-202-379) and Form S-8 (No. 333-43569, No. 333-94851, No. 333-115844, No. 333-150992, No. 333-167076, No. 333-181704, and No. 333-204929).

Very truly yours,

By /s/ DeGolyer and MacNaughton

DEGOLYER AND MACNAUGHTON
Texas Registered Engineering Firm F-716

**Exhibit 31(1)**

I, John B. Hess, certify that:

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

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

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

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

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

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

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

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

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

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

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

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

Date: February 25, 2016

**Exhibit 31(2)**

I, John P. Rielly, certify that:

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

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

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

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

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

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

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

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

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

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

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

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

Date: February 25, 2016

**Exhibit 32(1)**

**CERTIFICATION PURSUANT TO**

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

In connection with the Annual Report of Hess Corporation (the Corporation) on Form 10-K for the period ended December 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, John B. Hess, Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

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

Date: February 25, 2016

**Exhibit 32(2)**

**CERTIFICATION PURSUANT TO**

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

In connection with the Annual Report of Hess Corporation (the Corporation) on Form 10-K for the period ended December 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, John P. Rielly, Senior Vice President and Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

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

Date: February 25, 2016

**Exhibit 99.1**

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

February 3, 2016

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

Ladies and Gentlemen:

Pursuant to your request, we have conducted a reserves audit of the net proved oil, condensate, natural gas liquids (NGL), and gas reserves, as of December 31, 2015, of certain selected properties in which Hess Corporation (Hess) has represented that it owns an interest to determine the reasonableness of Hess' estimates. The audit was completed on February 3, 2016. Hess has represented to us that these properties account for approximately 82.8 percent on a net equivalent barrel basis of Hess' net proved reserves, as of December 31, 2015 and that the net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the Securities and Exchange Commission (SEC) of the United States. We have reviewed information provided to us by Hess that it represents to be Hess' estimates of the net reserves, as of December 31, 2015, for the same properties as those which we evaluated. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S-K and is to be used for inclusion in certain SEC filings by Hess.

Reserves estimates included herein are expressed as net reserves as represented by Hess. Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2015. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Hess after deducting all interests owned by others.

Certain properties in which Hess has an interest are subject to the terms of various profit sharing agreements. The terms of these agreements generally allow for working interest participants to be reimbursed for portions of capital costs and operating expenses and to share in the profits. The reimbursements and profit proceeds are converted to a barrel of oil equivalent or cubic foot of gas equivalent by dividing by product prices to determine the "entitlement reserves." These entitlement reserves are equivalent in principle to net reserves and are used to calculate an equivalent net share, termed an "entitlement interest." In this report, Hess net reserves or interest for certain properties subject to these agreements is the entitlement based on Hess' working interest.

Estimates of oil, condensate, NGL, and gas reserves should be regarded only as estimates. Such estimates are based upon information that is currently available and may change as further production history and additional information become available. Such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this audit were obtained from reviews with Hess personnel, from Hess files, from records on file with the appropriate regulatory agencies, and from public sources. Additionally, this information includes data supplied by IHS Global Inc.; Copyright 2015 IHS Global Inc. In the preparation of this report we have relied, without independent verification, upon such information furnished by Hess with respect to property interests, production from such properties, costs of operation and development, prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report. In our opinion, the adequacy and quality of the data provided to us was sufficient for us to conduct this reserves audit.

The Hess net proved reserves attributable to these properties, as of December 31, 2015, and which represent approximately 82.8 percent of total Hess net reserves on a net equivalent barrel basis, are as follows, expressed in millions of barrels (MMbbl), billions of cubic feet (Bcf), and millions of barrels of oil equivalent (MMboe):

| | Estimated by Hess Net Proved Reserves as of December 31, 2015 | | | |
|---|---|---|---|---|
| | **Oil and Condensate (MMbbl)** | **Natural Gas Liquids (MMbbl)** | **Gas (Bcf)** | **Oil Equivalent (MMboe)** |
| United States | 330 | 70 | 460 | 477 |
| Norway | 170 | 28 | 191 | 229 |
| Denmark | 32 | 0 | 43 | 39 |
| Africa | 34 | 0 | 20 | 37 |
| Asia | 5 | 0 | 667 | 116 |
| **Total** | **571** | **99** | **1,381** | **899** |

Note: Gas is converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

## Opinion

The assumptions, data, methods, and procedures used by DeGolyer and MacNaughton to conduct the reserves audit are appropriate for the purposes of this report.

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

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

In comparing the detailed net proved reserves estimates by field prepared by us and by Hess, we have found differences, both positive and negative, resulting in an aggregate difference of less than 1 percent when compared on the basis of net equivalent barrels. It is our opinion that the total net proved reserves estimates prepared by Hess, as of December 31, 2015, on the properties reviewed by us and referred to in the table above, when compared on the basis of net equivalent barrels, do not differ materially from those prepared by us.

## Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

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

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the fluid properties, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure, and gas-oil ratio behavior, was used in the estimation of reserves.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses, whichever occurred earlier.

Petroleum reserves estimated by Hess and by us are classified as proved and are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. Reserves were estimated only to the limit of economic production rates under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions.

Gas quantities herein are expressed as marketable gas at the legal pressure and temperature base of the state or area in which the property is located. Marketable gas is defined as the total gas produced from the reservoir after reduction for shrinkage resulting from field separation; processing, including removal of nonhydrocarbon gas to meet pipeline specifications; and flare and other losses but not from fuel usage. Fuel gas is included as reserves. Oil and condensate reserves estimated herein are those to be recovered by conventional lease separation. Oil, NGL, and condensate reserves estimates included in this report are expressed in terms of barrels representing 42 United States gallons per barrel. NGL reserves are those attributed to the leasehold interests according to processing agreements and involve low temperature separation.

**Definition of Reserves**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in Rule 4-10(a)(2) of Regulation S-X, or by other evidence using reliable technology establishing reasonable certainty.

## Primary Economic Assumptions

The following economic assumptions were used for estimating existing and future prices and costs:

*Oil and Condensate Prices*

Hess has represented that the oil and condensate prices were based on a 12-month average price (reference price), calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The 12-month average reference prices used were $50.13 per barrel for West Texas Intermediate and $55.10 per barrel for Brent. Hess supplied appropriate differentials by field to the relevant reference prices and the prices were held constant thereafter. The volume-weighted average price for the fields evaluated was $47.69 per barrel.

*NGL Prices*

Hess has represented that the NGL prices were based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. These prices were held constant over the lives of the properties. The volume-weighted average NGL price for the fields evaluated was $10.43 per barrel.

*Gas Prices*

Hess has represented that the non-contracted gas prices were based on reference prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The 12-month average reference price for NYMEX was $2.63 per thousand cubic feet and the UK International Petroleum Exchange reference price was $6.59 per thousand cubic feet. The gas prices were adjusted for each property using differentials to NYMEX or the UK International Petroleum Exchange furnished by Hess and held constant thereafter. A portion of the gas reserves evaluated are in international properties where the gas is sold based on contracted prices. The contract was used to determine the gas price but inflation was not taken into account in the calculation of the average price. The volume-weighted average gas price for the fields evaluated was $4.25 per thousand cubic feet.

*Operating Expenses and Capital Costs*

Operating expenses and capital costs, based on information provided by Hess, were used in estimating future costs required to operate the properties. Future costs are typically based on existing costs and, where appropriate, adjusted to reflect planned changes in operating conditions. These costs were not escalated for inflation.

**Possible Effects of Regulations**

Hess' oil and gas reserves have been estimated assuming the continuation of the current regulatory environment. Foreign oil-producing countries, including members of the Organization of Petroleum Exporting Countries (OPEC), may impose production quotas which limit the supply of oil that can be produced. Generally, these production quotas affect the timing of production, rather than the total volume of oil or gas reserves estimated.

Changes in the regulatory environment by host governments may impact the operating environment and oil and gas reserves estimates of industry participants. Such regulatory changes could include increased mandatory government participation in producing contracts, changes in royalty terms, cancellation or amendment of contract rights, or expropriation or nationalization of property. While the oil and gas industry is subject to regulatory changes that could affect an industry participant's ability to recover its oil and gas reserves, neither we nor Hess are aware of any such governmental actions which restrict the recovery of the December 31, 2015, estimated oil and gas reserves.

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

Submitted,

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

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

[SEAL]

**CERTIFICATE of QUALIFICATION**

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

1. That I am a Senior Vice President of DeGolyer and MacNaughton, which company did prepare the letter report dated February 3, 2016, on the proved reserves audit of certain properties attributable to Hess Corporation, and that I, as Senior Vice President, was responsible for the preparation of this letter report.

2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in 1982; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers and that I have in excess of 33 years of experience in oil and gas reservoir studies and reserves evaluations.

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

[SEAL]