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, 2012

or

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

Commission File Number 1-1204

Hess Corporation
(Exact name of Registrant as specified in its charter)

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

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

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

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

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

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

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

Indicate by check mark whether the registrant 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 ☐ (Do not check if a smaller reporting company)	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 $13,123,000,000 computed using the outstanding common shares and closing market price on June 30, 2012.

At December 31, 2012, there were 341,527,617 shares of Common Stock outstanding.

Part III is incorporated by reference from the Proxy Statement for the 2013 annual meeting of stockholders.

HESS CORPORATION

Form 10-K

TABLE OF CONTENTS

Table of Contents

PART I

Items 1 and 2. Business and Properties

Hess Corporation (the Registrant) is a Delaware corporation, incorporated in 1920. The Registrant and its subsidiaries (collectively referred to as the Corporation or Hess) operate in two segments, Exploration and Production (E&P) and Marketing and Refining (M&R). The E&P segment explores for, develops, produces, purchases, transports and sells crude oil and natural gas. The M&R segment purchases, markets and trades refined petroleum products, natural gas and electricity. The Corporation also operates terminals and retail gasoline stations, most of which include convenience stores, that are located on the East Coast of the United States. Through February 2013, the Corporation also manufactured refined petroleum products. In January 2013, the Corporation announced its decision to cease refining operations at its Port Reading facility in February and pursue the sale of its terminal network. In January 2012, HOVENSA L.L.C. (HOVENSA), a 50% owned joint venture in the U.S. Virgin Islands, shut down its refinery. The Corporation and its joint venture partner plan to pursue the sale of HOVENSA, while the complex is operated as an oil storage terminal.

The Corporation has for more than two years been engaged in transforming itself into an essentially E&P business focused on the Corporation's most promising properties and operations and intends to continue to pursue this strategy.

See also the Overview in Management's Discussion and Analysis of Financial Condition and Results of Operations.

Exploration and Production

The Corporation's 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)	
	2012	2011	2012	2011	2012	2011
	(Millions of barrels)		(Millions of mcf)		(Millions of barrels)	
Developed						
United States	**280**	190	**232**	199	**318**	223
Europe (c)	**181**	212	**190**	273	**213**	258
Africa	**188**	194	**122**	63	**208**	204
Asia	**27**	25	**676**	677	**140**	138
	676	621	**1,220**	1,212	**879**	823
Undeveloped						
United States	**193**	183	**168**	161	**222**	210
Europe (c)	**235**	282	**167**	290	**263**	331
Africa	**46**	56	**20**	8	**49**	57
Asia	**21**	27	**720**	752	**140**	152
	495	548	**1,075**	1,211	**674**	750
Total						
United States	**473**	373	**400**	360	**540**	433
Europe (c)	**416**	494	**357**	563	**476**	589
Africa	**234**	250	**142**	71	**257**	261
Asia	**48**	52	**1,396**	1,429	**280**	290
	1,171	1,169	**2,295**	2,423	**1,553**	1,573

(a) Total natural gas liquids reserves were 136 million barrels (76 million barrels developed and 60 million barrels undeveloped) at December 31, 2012 and 113 million barrels (56 million barrels developed and 57 million barrels undeveloped) at December 31, 2011.

Table of Contents

Natural gas liquids reserves in the United States were 78% and 70% at December 31, 2012 and 2011, respectively. Natural gas liquids reserves in Norway were 17% and 22% at December 31, 2012 and 2011, respectively.

(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% and 23% of the Corporation's total reserves at December 31, 2012 and 2011, respectively, were as follows:*

	Crude Oil, Condensate & Natural Gas Liquids		Natural Gas		Total Barrels of Oil Equivalent (BOE)	
	2012	2011	2012	2011	2012	2011
	(Millions of barrels)		(Millions of mcf)		(Millions of barrels)	
Developed	**102**	108	**73**	137	**114**	131
Undeveloped	**182**	185	**146**	251	**207**	227
Total	**284**	293	**219**	388	**321**	358

On a barrel of oil equivalent (boe) basis, 43% of the Corporation's worldwide proved reserves were undeveloped at December 31, 2012 compared with 48% at December 31, 2011. Proved reserves held under production sharing contracts at December 31, 2012 totaled 10% of crude oil and natural gas liquids reserves and 52% of natural gas reserves, compared with 12% of crude oil and natural gas liquids reserves and 51% of natural gas reserves at December 31, 2011. See the Supplementary Oil and Gas Data on pages 80 through 88 in the accompanying financial statements for additional information on the Corporation's oil and gas reserves.

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

	2012	2011	2010
Crude oil (thousands of barrels per day)			
United States			
Bakken	**47**	26	12
Other Onshore	**13**	11	11
Total Onshore	**60**	37	23
Offshore	**48**	44	52
Total United States	**108**	81	75
Europe			
Russia	**49**	45	42
United Kingdom	**15**	14	19
Norway*	**11**	20	16
Denmark	**9**	10	11
	84	89	88
Africa			
Equatorial Guinea	**48**	54	69
Libya	**20**	4	23
Algeria	**7**	8	11
Gabon	**—**	—	10
	75	66	113
Asia			
Azerbaijan	**7**	6	7
Indonesia	**6**	3	2
Other	**4**	4	4
	17	13	13
Total	**284**	249	289

Table of Contents

	2012	2011	2010
Natural gas liquids (thousands of barrels per day)			
United States			
Bakken	**5**	2	2
Other Onshore	**5**	5	5
Total Onshore	**10**	7	7
Offshore	**6**	6	7
Total United States	**16**	13	14
Europe*	**2**	3	3
Asia	**1**	1	1
Total	**19**	17	18
Natural gas (thousands of mcf per day)			
United States			
Bakken	**27**	13	9
Other Onshore	**27**	26	29
Total Onshore	**54**	39	38
Offshore	**65**	61	70
Total United States	**119**	100	108
Europe			
United Kingdom	**25**	41	93
Norway*	**10**	29	29
Denmark	**8**	11	12
	43	81	134
Asia and Other			
Joint Development Area of Malaysia/Thailand (JDA)	**252**	267	282
Thailand	**90**	84	85
Indonesia	**66**	56	50
Malaysia	**39**	35	8
Other	**7**	—	2
	454	442	427
Total	**616**	623	669
Barrels of oil equivalent (per day)**	**406**	370	418

* *Norway production for 2012 included 11 thousand barrels per day of crude oil, 0.5 thousand barrels per day of natural gas liquids and 8 thousand mcf per day of natural gas from the Valhall Field. Norway production for 2011 included 18 thousand barrels per day of crude oil, 1 thousand barrels per day of natural gas liquids and 15 thousand mcf per day of natural gas from the Valhall Field. Norway production for 2010 included 14 thousand barrels per day of crude oil, 1 thousand barrels per day of natural gas liquids and 13 thousand mcf per day of natural gas from the Valhall Field.*

** *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. See the average selling prices in the table on page 8.*

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

United States

At December 31, 2012, 35% of the Corporation's total proved reserves were located in the United States. During 2012, 41% of the Corporation's crude oil and natural gas liquids production and 19% of its natural gas production were from United States operations. The Corporation's production in the United States was from offshore properties in the Gulf of Mexico, and onshore properties principally in the Williston Basin of North Dakota as well as in the Permian Basin of Texas.

***Onshore*:** In North Dakota, the Corporation holds approximately 725,000 net acres in the Bakken oil shale play (Bakken). In 2012, the Corporation invested $3.1 billion in drilling and infrastructure projects in the Bakken and substantially completed its "held by production" drilling program undertaken during 2011 and 2012 to hold acreage from the acquisitions in 2010 of TRZ Energy, LLC and American Oil & Gas Inc. (American Oil & Gas). In the fourth quarter, the Corporation moved to pad drilling, which involves sequentially drilling a number of wells on a pad followed by sequential completion of the wells. This pad drilling is expected to lead to a temporary flattening of the production profile until mid-2013. Bakken production is expected to average between 64,000 barrels of oil equivalent per day (boepd) and 70,000 boepd for the full year of 2013, with most of the increase expected to occur in the second half of the year. Infrastructure investments in 2012 included completion of a crude oil rail loading and storage facility, which was operational in the first quarter, and the continued expansion of the Tioga gas plant. In 2013, the Corporation anticipates operating 14 rigs and completing the Tioga gas plant expansion project in the fourth quarter.

In Texas, the Corporation operates and holds a 34% interest in the Seminole-San Andres Unit. The Corporation also holds approximately 45,000 net acres in the Cotulla area of the Eagle Ford Shale, where first production commenced in May 2011.

In Ohio's Utica Shale, the Corporation owns a 100% interest in approximately 95,000 acres. The Corporation also owns a 50% undivided interest in CONSOL Energy Inc.'s (CONSOL) approximately 200,000 gross acres, which will be amended pursuant to the joint venture's ongoing title verification procedure. CONSOL announced on January 31, 2013, that there are chain of title issues with respect to approximately 36,000 acres, most of which likely cannot be cured and that the value of the Corporation's carry obligation associated with these acres will reduce by approximately $146 million. The reduction in carry and validation of title on other acreage is being separately analyzed by the Corporation and will not be finally determined until the title verification process is completed. In 2012, the Corporation participated in 12 wells, 10 of which were joint venture wells with CONSOL. The Corporation has also contracted to acquire seismic data. In 2013, the Corporation plans to drill five wells on its 100% owned acreage and 27 wells with CONSOL, as well as acquire the seismic data.

Offshore: The Corporation's production offshore in the Gulf of Mexico was principally from the Shenzi (Hess 28%), Llano (Hess 50%), Conger (Hess 38%), Baldpate (Hess 50%), Hack Wilson (Hess 25%) and Penn State (Hess 50%) fields.

At the Shenzi Field, development drilling continued during 2012 with the completion of two wells. During 2013, the operator plans to complete two production wells and drill one additional water injection well. At the outside operated Llano Field, a successful workover was completed on the Llano #3 well and drilling of the Llano #4 production well commenced in fourth quarter of 2012. At the operated Conger Field, the Corporation plans to acquire seismic data during 2013.

At the Tubular Bells Field (Hess 57%) in the Mississippi Canyon Area of the deepwater Gulf of Mexico, the field development was advanced with the ongoing construction of a floating production system, batch drilling of the top hole sections of the well program and drilling and completion of one well. Development drilling will continue throughout 2013 and first production is anticipated in 2014.

During the third quarter of 2012, the Corporation signed an exchange agreement with the partners of Green Canyon Block 512 that contains the Knotty Head discovery and is in the same reservoir as the Corporation's Pony discovery on the adjacent Block 468. Under this agreement, the Corporation was appointed operator and has a 20% working interest in the blocks, now collectively referred to as Stampede. Field development planning is progressing and the project is targeted for sanction in 2014.

At December 31, 2012, the Corporation had interests in 252 blocks in the Gulf of Mexico, of which 223 were exploration blocks comprising approximately 855,000 net undeveloped acres, with an additional 66,000 net acres held for production and development operations. During 2012, 49 leases in which the Corporation held an interest either expired or were relinquished.

Europe

At December 31, 2012, 31% of the Corporation's total proved reserves were located in Europe (Norway 21%, Denmark 4%, Russia 5% and United Kingdom 1%). During 2012, 28% of the Corporation's crude oil and natural gas liquids production and 7% of its natural gas production were from European operations.

Norway: Substantially all of the 2012 Norwegian production was from the Corporation's interest in the Valhall Field (Hess 64%). At December 31, 2012, the Corporation also held an interest in the Hod Field (Hess 63%).

At the Valhall Field, a multi-year redevelopment project was completed in early 2013. The project included the installation of a new production, utilities and accommodation platform and expansion of gross production capacity to 120,000 barrels of liquids per day and 143,000 mcf of natural gas per day. In July 2012, the field was shut-in to complete the installation and commissioning of the new facilities and production resumed in January 2013. The operator plans a multi-year development drilling program commencing in 2013.

In January 2012, the Corporation completed the sale of its interest in the Snohvit Field (Hess 3%), a liquefied natural gas development, offshore Norway.

United Kingdom: Production in the United Kingdom North Sea was from the Corporation's outside-operated interests in the Beryl (Hess 22%), Nevis (Hess 27%), Schiehallion (Hess 16%) and Bittern (Hess 28%) fields. The Corporation also has interests in the Atlantic (Hess 25%), Cromarty (Hess 90%), Fife, Flora and Angus (Hess 85%), Fergus (Hess 65%), Ivanhoe and Rob Roy (Hess 77%), Renee (Hess 14%) and Rubie (Hess 19%) fields. These fields are no longer producing and decommissioning activities have commenced.

In September 2012, the Corporation completed the sale of its interests in the Schiehallion Field, its share of the associated floating production, storage and offloading vessel, and the West of Shetland pipeline system. In October 2012, the Corporation completed the sale of its interests in the Bittern Field and the associated Triton floating production, storage and offloading vessel. In October 2012, the Corporation also announced that it had reached an agreement to sell its interests in the Beryl and Nevis fields and its interest in the Scottish Area Gas Evacuation (SAGE) pipeline (Hess 11%). This transaction was completed in January 2013, see Note 21, Subsequent Events in the notes to the Consolidated Financial Statements.

Denmark: Production comes from the Corporation's operated interest in the South Arne Field (Hess 62%), offshore Denmark. In 2012, the Corporation continued its phase three development program where two new wellhead platforms were successfully installed in the field. Hook-up and commissioning of the new platforms was ongoing at year-end and development drilling is expected to commence in the first half of 2013. First oil from the phase three development is anticipated in the second half of 2013.

Russia: The Corporation's activities in Russia are conducted through its interest in Samara-Nafta, a subsidiary operating in the Volga-Urals region (Hess 90%). As of December 31, 2012, this subsidiary had exploration and production rights in 23 license areas. In November 2012, the Corporation announced that it will pursue the sale of Samara-Nafta.

France: The Corporation has a 100% interest in and is operator of approximately 630,000 acres in the Paris Basin. In July 2011, the French government implemented a law prohibiting the use of hydraulic fracturing. In 2013, the Corporation plans to drill three conventional vertical wells, which will be logged and cored to gain subsurface data.

Africa

At December 31, 2012, 16% of the Corporation's total proved reserves were located in Africa (Equatorial Guinea 4%, Libya 11% and Algeria 1%). During 2012, 25% of the Corporation's crude oil and natural gas liquids production was from its African operations.

Equatorial Guinea: The Corporation is operator and owns an interest in Block G (Hess 85% paying interest) which contains the Ceiba Field and the Okume Complex. The national oil company of Equatorial Guinea holds a 5% carried interest in Block G. During 2012, the Corporation completed three workovers and drilled three production wells in the Ceiba Field with a fourth well spud late in the fourth quarter. During 2013, the Corporation plans to complete this well and tie in the four wells. The Corporation also plans to drill two production wells at the Okume Complex beginning in the latter part of 2013.

Libya: The Corporation, in conjunction with its Oasis Group partners, has production operations in the Waha concessions in Libya (Hess 8%). The Corporation also owns a 100% interest in offshore exploration Area 54 in the Mediterranean Sea, where two wells discovered natural gas. In response to civil unrest in Libya and the resulting imposition of economic sanctions, production at the Waha fields was suspended in the first quarter of 2011. As a result, the Corporation delivered force majeure notices to the Libyan government covering its exploration and production interests. During the fourth quarter of 2011, the sanctions were lifted, force majeure was withdrawn at Waha and production resumed. The force majeure covering the Corporation's offshore exploration interests was withdrawn in March 2012. The Corporation is pursuing commercial options for its exploration interests.

Algeria: The Corporation has a 49% interest in a venture with the Algerian national oil company that redeveloped three oil fields. The Corporation also has an interest in Bir El Msana (BMS) Block 401C (Hess 45%). The Corporation sanctioned a small development project at BMS in 2011 and advanced the construction of facilities and development drilling during 2012.

Ghana: The Corporation holds a 100% paying interest and is operator of the Deepwater Tano Cape Three Points license. The Ghana National Petroleum Corporation holds a 10% carried interest in the block. Through February 2013, the Corporation has drilled seven consecutive successful exploration wells, including four discoveries made in 2012 and two completed in early 2013. Based on the results of these wells, the Corporation plans to submit an appraisal plan to the Ghanaian government for approval on or before June 2, 2013 and has also begun pre-development studies on the block.

Asia

At December 31, 2012, 18% of the Corporation's total proved reserves were located in the Asia region (JDA 8%, Indonesia 5%, Thailand 3%, Azerbaijan 1% and Malaysia 1%). During 2012, 6% of the Corporation's crude oil and natural gas liquids production and 74% of its natural gas production were from its Asian operations.

Joint Development Area of Malaysia/Thailand (JDA): The Corporation owns an interest in Block A-18 of the JDA (Hess 50%) in the Gulf of Thailand. In 2012, the operator continued development drilling, constructed wellhead platforms and sanctioned a compression project. In 2013, the operator intends to progress the compression project and the installation of new wellhead platforms.

Malaysia: The Corporation's production in Malaysia comes from its interest in Block PM301 (Hess 50%), which is adjacent to and is unitized with Block A-18 of the JDA where the natural gas is processed. The Corporation also owns a 50% interest and is the operator of Blocks PM302, PM325 and PM326B located in the North Malay Basin (NMB), offshore Peninsular Malaysia, where in 2012 it signed agreements with its partner to develop nine discovered natural gas fields as well as acquire seismic and drill exploration wells. First production from an early production system is forecast to commence in the second half of 2013 with a second phase of development targeted for first production in 2016. In addition, the Corporation owns an interest in Block SB302 (Hess 40%). Technical and commercial evaluations are underway to assess potential development alternatives for this block.

Indonesia: The Corporation's production in Indonesia comes from its interests offshore in the operated Ujung Pangkah project (Hess 75%) and the outside-operated Natuna A Field (Hess 23%). At the Pangkah Field, the Corporation drilled and completed five production wells during 2012 and plans further drilling in 2013. At the Natuna Field, construction began on two new wellhead platforms in 2012 and facility construction and other infrastructure work will continue in 2013.

The Corporation also owns interests in the offshore South Sesulu Block (Hess 100%), Timor Sea Block 1 (Hess 100%), Semai V Block (Hess 100%) and Kofiau Block (Hess 43%) as well as the West Timor Block (Hess 49%) that includes onshore and offshore acreage.

Thailand: The Corporation's production in Thailand comes from the offshore Pailin Field (Hess 15%) and the operated onshore Sinphuhorm Block (Hess 35%). During 2012, development drilling continued at Pailin. In 2013, there will be further development drilling at both Pailin and Sinphuhorm.

Azerbaijan: The Corporation has interests in the Azeri-Chirag-Guneshli (ACG) fields (Hess 3%) in the Caspian Sea and in the Baku-Tbilisi-Ceyhan (BTC) oil transportation pipeline company (Hess 2%). In September 2012, the Corporation reached an agreement to sell its interests in ACG and BTC. This transaction is expected to close in the first quarter of 2013.

Australia: The Corporation holds an interest in an exploration license covering approximately 780,000 acres in the Carnarvon basin offshore Western Australia (WA-390-P Block, also known as Equus) (Hess 100%). The Corporation has drilled all of the 16 commitment wells on the block, 13 of which were natural gas discoveries. Appraisal of the discoveries was completed in mid-2012. Development planning and commercial activities, including negotiations with potential liquefaction partners continued in 2012 and will continue in 2013. Successful negotiation with a third party liquefaction partner is necessary before the Corporation can negotiate a gas sales agreement and sanction development of the project.

The Corporation also has a participation agreement under which it has the option to earn a 63% working interest in more than 6.2 million acres in the Beetaloo Basin, onshore Northern Territory Australia (Hess 100% paying interest). In 2012, the Corporation completed its seismic data acquisition program. In addition, the Corporation acquired approximately 1.9 million net acres in the Canning Basin, Western Australia. An aeromagnetic survey of this acreage was completed in 2012.

Brunei: The Corporation has an interest in Block CA-1 (Hess 14%). In 2012, the operator drilled two wells, Jagus East and Julong East, which both encountered hydrocarbons. These wells are being evaluated and additional exploration and appraisal drilling is planned for 2014.

Kurdistan Region of Iraq: The Corporation is operator and has an 80% paying interest in the Dinarta and Shakrok exploration blocks, which have a combined area of more than 670 square miles. The terms of the production sharing contracts require the acquisition of 2D seismic and the drilling of at least one well on each of the blocks. During 2012, the Corporation commenced a seismic program on both of its blocks. The Corporation plans to complete this seismic program and commence drilling of its two commitment wells in 2013.

China: The Corporation has signed a joint study agreement with PetroChina to evaluate unconventional oil and gas resource opportunities covering approximately 200,000 gross acres in the Santanghu Basin.

Sales Commitments

In the E&P segment, the Corporation has contracts to sell fixed quantities of its natural gas and natural gas liquids (NGL) production. The natural gas contracts principally relate to producing fields in Asia. The most significant of these commitments relates to the JDA where the minimum contract quantity of natural gas is estimated at 107 million mcf per year based on current entitlements under a sales contract expiring in 2027. There are additional natural gas supply commitments on producing fields in Thailand and Indonesia which currently total approximately 46 million mcf per year under contracts expiring in years 2021 through 2029. The estimated total volume of production subject to sales commitments under all of these contracts is approximately 2.35 billion mcf of natural gas.

The Corporation also has NGL contracts relating to its Bakken production with delivery commitments beginning in November 2013. The minimum contract quantity under these contracts, which expire in 2023, is approximately 7 million barrels per year, or approximately 70 million barrels over the life of the contracts.

The Corporation has not experienced any significant constraints in satisfying the committed quantities required by its sales commitments and it anticipates being able to meet future requirements from available proved and probable reserves.

Natural gas is marketed by the M&R segment on a spot basis and under contracts for varying periods of time to local distribution companies, and commercial, industrial and other purchasers. These natural gas marketing activities are primarily conducted in the eastern portion of the United States, where the principal source of supply is purchased natural gas, not the Corporation’s production from the E&P segment. The Corporation has not experienced any significant constraints in obtaining the required supply of purchased natural gas.

Average selling prices and average production costs

	2012	2011	2010
Average selling prices (a)			
Crude oil (per barrel)			
United States	**$ 92.32**	$ 98.56	$ 75.02
Europe (b)	**74.14**	80.18	58.11
Africa	**89.02**	88.46	65.02
Asia	**107.45**	111.71	79.23
Worldwide	**86.94**	89.99	66.20
Natural gas liquids (per barrel)			
United States	**$ 40.75**	$ 58.59	$ 47.92
Europe (b)	**78.43**	75.49	59.23
Asia	**77.92**	72.29	63.50
Worldwide	**47.81**	62.72	50.49
Natural gas (per mcf)			
United States	**$ 2.09**	$ 3.39	$ 3.70
Europe (b)	**9.50**	8.79	6.23
Asia and other	**6.90**	6.02	5.93
Worldwide	**6.16**	5.96	5.63
Average production (lifting) costs per barrel of oil equivalent produced (c)			
United States	**$ 18.25**	$ 16.30	$ 12.61
Europe (b)	**29.56**	25.13	17.55
Africa	**14.45**	15.95	11.00
Asia and other	**11.13**	10.62	8.16
Worldwide	**18.52**	17.40	12.61

(a) Includes inter-company transfers valued at approximate market prices and the effect of the Corporation’s hedging activities.

(b) The average selling prices in Norway for 2012 were $109.23 per barrel for crude oil, $58.48 per barrel for natural gas liquids and $12.21 per mcf for natural gas. The average selling prices in Norway for 2011 were $112.38 per barrel for crude oil, $62.07 per barrel for natural gas liquids and $9.77 per mcf for natural gas. The average selling prices in Norway for 2010 were $79.47 per barrel for crude oil, $52.26 per barrel for natural gas liquids and $7.32 per mcf for natural gas. The average production (lifting) costs in Norway in 2012 were $62.38 per barrel of oil equivalent produced, reflecting the shutdown of production from July 2012 through year-end. The average production (lifting) costs in Norway were $31.09 per barrel of oil equivalent produced in 2011 and $18.33 per barrel of oil equivalent produced in 2010.

(c) Production (lifting) costs consist of amounts incurred to operate and maintain the Corporation's producing oil and gas wells, related equipment and facilities, transportation costs 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).

The table above does 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, 2012

	Undeveloped Acreage (a)	
	Gross	Net
	(In thousands)	
United States	2,310	1,594
Europe (b)	1,517	1,278
Africa	8,009	4,625
Asia and other	15,322	9,937
Total (c)	27,158	17,434

(a) Includes acreage held under production sharing contracts.
(b) Gross and net undeveloped acreage in Norway was 61 thousand and 9 thousand, respectively.
(c) Licenses covering approximately 35% of the Corporation's net undeveloped acreage held at December 31, 2012 are scheduled to expire during the next three years pending the results of exploration activities. These scheduled expirations are largely in Africa, Asia and the United States.

Gross and net developed acreage and productive wells at December 31, 2012

	Developed Acreage Applicable to Productive Wells		Productive Wells (a)			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
	(In thousands)					
United States	1,177	795	1,767	776	58	47
Europe (b)	1,053	885	292	216	12	2
Africa	9,832	933	811	125	—	—
Asia	2,246	638	86	15	456	100
Total	14,308	3,251	2,956	1,132	526	149

(a) Includes multiple completion wells (wells producing from different formations in the same bore hole) totaling 31 gross wells and 21 net wells.
(b) Gross and net developed acreage in Norway was 57 thousand and 36 thousand, respectively. Gross and net productive oil wells in Norway were 46 and 30, respectively.

Number of net exploratory and development wells drilled at December 31

	Net Exploratory Wells			Net Development Wells		
	2012	2011	2010	2012	2011	2010
Productive wells						
United States	**3**	20	—	**184**	98	83
Europe	**3**	6	1	**23**	25	18
Africa	**3**	1	1	**1**	1	11
Asia and other	**3**	4	6	**20**	18	7
	12	31	8	**228**	142	119
Dry holes						
United States	**1**	—	5	**—**	—	—
Europe	**3**	2	—	**—**	—	—
Africa	**—**	1	2	**—**	—	1
Asia and other	**2**	1	2	**—**	—	—
	6	4	9	**—**	—	1
Total	**18**	35	17	**228**	142	120

Table of Contents

Number of wells in process of drilling at December 31, 2012

	Gross Wells	Net Wells
United States	117	53
Europe*	17	15
Africa	6	2
Asia	28	9
Total	168	79

* *Gross and net wells in process of drilling in Norway were 3 and 2, respectively.*

Marketing and Refining

Marketing

The Corporation markets refined petroleum products, natural gas and electricity on the East Coast of the United States to the motoring public, wholesale distributors, industrial and commercial users, other petroleum companies, governmental agencies and public utilities.

The Corporation had 1,361 HESS® gasoline stations at December 31, 2012, including stations owned by its WilcoHess joint venture (Hess 44%). Approximately 93% of the gasoline stations are operated by the Corporation or WilcoHess. Of the operated stations, 96% have convenience stores on the sites. Most of the Corporation's gasoline stations are in New York, New Jersey, Pennsylvania, Florida, Massachusetts, North Carolina and South Carolina.

The table below summarizes marketing sales volumes:

	2012*	2011*	2010*
Refined petroleum product sales (thousands of barrels per day)			
Gasoline	**209**	222	242
Distillates	**113**	123	120
Residuals	**53**	65	69
Other	**14**	20	40
Total refined petroleum product sales	**389**	430	471
Natural gas (thousands of mcf per day)	**2,300**	2,200	2,000
Electricity (megawatts round the clock)	**4,500**	4,400	4,100

* *Of total refined petroleum products sold, a total of approximately 16%, 37% and 41% was obtained from HOVENSA and Port Reading in 2012, 2011 and 2010, respectively. In January 2012, HOVENSA shut down its refinery. In January 2013, the Corporation announced its decision to cease refining operations in February at its Port Reading facility.*

The Corporation does not anticipate any disruption to product supply to its Marketing operations as a result of the shutdown of its Port Reading facility.

The Corporation owns 19 terminals with an aggregate storage capacity of 28 million barrels in its East Coast marketing areas, including the storage capacity at Port Reading. The Corporation also owns a terminal in St. Lucia with a storage capacity of 10 million barrels, which is operated for third party storage. In January 2013, the Corporation announced that it will pursue the sale of its terminal network.

During 2012, operations commenced at the Bayonne Energy Center, LLC (Hess 50%), a joint venture established to build and operate a 512-megawatt natural gas fueled electric generating station in Bayonne, New Jersey, which provides power to New York City. During 2012, the Corporation also formed a joint venture (Hess 50%) to build a 655-megawatt natural gas fueled electric generating facility in Newark, New Jersey. In addition, a subsidiary of the Corporation is exploring the development of fuel cell and hydrogen reforming technologies.

Refining

HOVENSA: The Corporation owns a 50% interest in HOVENSA, a joint venture with a subsidiary of Petroleos de Venezuela S.A. (PDVSA). In January 2012, HOVENSA shut down its refinery in St. Croix, U.S. Virgin Islands. During 2012 and continuing into 2013, HOVENSA and the Government of the Virgin Islands engaged in discussions pertaining to HOVENSA's plan to run the facility as an oil storage terminal while the

Corporation and its joint venture partner pursue a sale of HOVENSA. For further discussion of the refinery shutdown, see Note 5, HOVENSA L.L.C. Joint Venture, in the notes to the Consolidated Financial Statements.

Port Reading Facility: The Corporation owns a fluid catalytic cracking facility in Port Reading, New Jersey, with a capacity of 70,000 barrels per day. This facility, which processes residual fuel oil and vacuum gas oil, operated at a rate of 59,000 barrels per day in 2012, 63,000 barrels per day in 2011 and 55,000 barrels per day in 2010. Substantially all of Port Reading's production was gasoline and heating oil. In January 2013, the Corporation announced its decision to cease refining operations in February at its Port Reading facility.

The Corporation has a 50% voting interest in a consolidated partnership that trades energy-related commodities, securities and derivatives. The Corporation also takes energy commodity and derivative trading positions for its own account.

For additional financial information by segment see Note 18, Segment Information in the notes to the Consolidated Financial Statements.

Competition and Market Conditions

See Item 1A. Risk Factors Related to Our Business and Operations, for a discussion of competition and market conditions.

Other Items

Gulf of Mexico Update

The Corporation currently holds interests in 223 exploration blocks in the Gulf of Mexico, in addition to 29 developed blocks. The Corporation received approval for its oil spill response plan for the Gulf of Mexico in May 2012 and is currently awaiting approval for an updated Gulf of Mexico Operator Oil Spill Contingency Plan in response to recent regulatory changes. The Corporation also fully implemented the Bureau of Safety and Environmental Enforcement required, Safety and Environmental Management System in 2012.

Emergency Preparedness and Response Plans and Procedures

The Corporation has 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 the Corporation's plans. The Corporation's 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 its global operations, the Corporation maintains 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 Well Containment Company (MWCC), Wild Well Control (WWC), National Response Corporation (NRC) and Oil Spill Response (OSR). CGA is a regional spill response organization and MWCC provides the equipment and personnel to contain an underwater well control incident in the Gulf of Mexico. WWC provides firefighting, well control and engineering services globally. NRC and OSR are global response organizations and are available to assist the Corporation when needed anywhere in the world. In addition to owning response assets in their own right, these organizations maintain business relationships that provide immediate access to additional critical response support services if required. These owned response assets included nearly 300 recovery and storage vessels and barges, more than 250 skimmers, over 300,000 feet of boom, and significant quantities of dispersants and other ancillary equipment, including aircraft. If the Corporation were to engage these organizations to obtain additional critical response support services, it would fund such services and seek reimbursement under its insurance coverage described below. In certain circumstances, the Corporation pursues and enters into mutual aid agreements with other companies and government cooperatives to receive and provide oil spill response equipment and personnel support. The Corporation maintains close associations with emergency response organizations through its representation on the Executive Committee of CGA and the Board of Directors of OSR.

The Corporation continues 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

The Corporation maintains insurance coverage that includes coverage for physical damage to its 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 the Corporation against liability from all potential consequences and damages.

The amount of insurance covering physical damage to the Corporation's property and liability related to negative environmental effects resulting from a sudden and accidental pollution event, excluding Atlantic Named Windstorm coverage for which it is 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 $2.25 billion in total, depending on the asset coverage level, as described above. Additionally, the Corporation carries insurance which provides third party coverage for general liability, and sudden and accidental pollution, up to $1 billion.

Other insurance policies provide coverage for, among other things: charterer's legal liability, in the amount of $500 million per occurrence and aircraft liability, in the amount of $300 million per occurrence.

The Corporation's 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, the Corporation's drilling contracts (and most of its 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.

The Corporation is customarily responsible for, and indemnifies the Contractor against all claims, including those from third-parties, to the extent attributable to pollution or contamination by substances originating from its reservoirs or other property (regardless of fault, including gross negligence and willful misconduct) and the Contractor is responsible for and indemnifies the Corporation for all claims attributable to pollution emanating from the Contractor's property. Additionally, the Corporation is generally liable for all of its own losses and most third-party claims associated with catastrophic losses such as blowouts, cratering and loss of hole, regardless of cause, although exceptions for losses attributable to gross negligence and/or willful misconduct do exist. Lastly, many 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, not covered by or in excess of insurance carried by 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 a party, in which case such party is solely liable. However, under some production sharing contracts between a governmental entity and commercial parties, liability of the commercial parties to the governmental 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 the Corporation's financial condition or results of operations. The Corporation spent $19 million in 2012 for environmental remediation. The Corporation anticipates capital expenditures for facilities, primarily to comply with federal, state and local environmental standards, other than for the low sulfur requirements, of approximately $75 million in 2013 and approximately $60 million in 2014. For further discussion of environmental matters see the Environment, Health and Safety section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Number of Employees

The number of persons employed by the Corporation at year-end was approximately 14,775 in 2012 and 14,350 in 2011.

Other

The Corporation's internet address is www.hess.com. On its website, the Corporation makes available free of charge its 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 the Corporation electronically files with or furnishes such material to the Securities and Exchange Commission. The contents of the Corporation's website are not incorporated by reference in this report. Copies of the Corporation's Code of Business Conduct and Ethics, its Corporate Governance Guidelines and the charters of the Audit Committee, the Compensation and Management Development Committee and the Corporate Governance and Nominating Committee of the Board of Directors are available on the Corporation's website and are also available free of charge upon request to the Secretary of the Corporation at its principal executive offices. The Corporation has also filed with the New York Stock Exchange (NYSE) its annual certification that the Corporation's Chief Executive Officer is unaware of any violation of the NYSE's corporate governance standards.

Item 1A. Risk Factors Related to Our Business and Operations

Our business activities and the value of our securities are subject to significant risk factors, including those described below. The risk factors described below 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, refined petroleum products and electricity, which can be very volatile. Our estimated proved reserves, revenue, operating cash flows, operating margins, future earnings and trading operations are highly dependent on the prices of crude oil, natural gas, refined petroleum products and electricity, which are volatile and influenced by numerous factors beyond our control. Changes in commodity prices can also have a material impact on collateral and margin requirements under our derivative contracts. The major foreign oil producing countries, including members of the Organization of Petroleum Exporting Countries (OPEC), 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 has a significant impact on the oil markets. The commodities trading markets as well as other supply and demand factors may also influence the selling prices of crude oil, natural gas, refined petroleum products and electricity. 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, the Corporation utilizes significant bank credit facilities. An inability to renew or replace such credit facilities or access other sources of funding as they mature would negatively impact our liquidity.

If we fail to successfully increase our reserves, our future crude oil and natural gas production will be adversely impacted. We own or have access to a finite amount of oil and gas reserves which will be depleted over time. Replacement of oil and gas production and reserves, including proved undeveloped reserves, is subject to successful exploration drilling, development activities, and enhanced recovery programs. Therefore, future oil and gas production is dependent on technical success in finding and developing additional hydrocarbon reserves. Exploration activity involves the interpretation of seismic and other geological and geophysical data, which does not always successfully predict the presence of commercial quantities of hydrocarbons. Drilling risks include unexpected adverse conditions, irregularities in pressure or formations, equipment failure, blowouts and weather interruptions. Future developments may be affected by unforeseen reservoir conditions which negatively affect recovery factors or flow rates. The costs of drilling and development activities have increased in recent years which could negatively affect expected economic returns. 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.

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.

We do not always control decisions made under joint operating agreements and the partners under such agreements may fail to meet their obligations. We conduct many of our exploration and production operations under joint operating agreements in which we may share control with other parties to the agreement. There is a risk that these parties may at any time have economic, business, or legal interests or goals that are inconsistent with ours, or these parties may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone. If we fail to jointly control operations, business decisions and other actions, 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, and changes in import and export regulations, limitations on access to exploration and development opportunities, as well as other political developments may affect our operations. As a result of the accident in April 2010 at the BP p.l.c. (BP) operated Macondo prospect in the Gulf of Mexico (in which the Corporation was not a participant) and the ensuing significant oil spill, a temporary drilling moratorium was imposed in the Gulf of Mexico. While this moratorium has since been lifted, significant new regulations have been imposed and further legislation and regulations may be proposed. The new regulatory environment has resulted in a longer permitting process and higher costs. The Dodd-Frank Wall Street Reform Act, enacted in 2010 (Dodd-Frank Act), delegated rulemaking responsibilities to carry out the Act to various U.S. government agencies. Our business could potentially be adversely impacted by one or more of the final rules under this Act, including potential additional costs to engage in certain derivative transactions. On August 22, 2012, the Securities and Exchange Commission issued final rules, as required by the Dodd-Frank Act, regarding disclosure of payments by resource extraction issuers, pursuant to which, beginning in 2014, we will be required to provide information about payments made to governments for the commercial development of oil, natural gas, or minerals.

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. Political 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. For example, the accident at the BP operated Macondo prospect in April 2010 resulted in a significant release of crude oil which caused extensive environmental and economic damage. Our operations are also subject to numerous United States 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.

Concerns have been raised in certain jurisdictions where we have operations concerning the safety and environmental impact of the drilling and development of unconventional 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. For example, a moratorium prohibiting hydraulic fracturing is currently impacting the Corporation’s operations in France.

Concerns about climate change may result in significant operational changes and expenditures and reduced demand for our products. 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, we market petroleum fuels, which through normal customer use result in the emission of greenhouse gases. Regulatory initiatives to reduce the use of these fuels may reduce our sales of, and revenues from, these products. Finally, to the extent that climate change may result in more extreme weather related events, we could experience increased costs related to prevention, maintenance and remediation of affected operations in addition to higher costs and lost revenues related to delays and shutdowns.

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, and in purchasing and marketing of refined petroleum products, natural gas and electricity. Many competitors, including national oil companies, are larger and have substantially greater resources. We are also in competition with producers and marketers of other forms of energy. Increased competition for worldwide oil and gas assets has significantly increased the cost of acquisitions. 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 accident at the Macondo prospect, pipeline interruptions and ruptures, severe weather, geological events, labor disputes or cyber-attacks. During 2012, we incurred charges for repairs and other expenses relating to the effects of Hurricane Sandy which hit the Northeast Coast of the United States. Although we maintain insurance coverage against property and casualty losses, there can be no assurance that such insurance will adequately protect the Corporation 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.

Item 3. Legal Proceedings

The Corporation, along with many other companies engaged in refining and marketing of gasoline, has 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 United States against producers of MTBE and petroleum refiners who produced gasoline containing MTBE, including the Corporation. 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. In 2008, the majority of the cases against the Corporation were settled. In 2010 and 2011, additional cases were settled including an action brought in state court by the State of New Hampshire. Two separate cases brought by the State of New Jersey and the Commonwealth of Puerto Rico remain unresolved. In 2007, a pre-tax charge of $40 million was recorded to cover all of the known MTBE cases against the Corporation.

The Corporation 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 the Corporation, relates to alleged releases from a petroleum bulk storage terminal in Newark, New Jersey now owned by the Corporation. The Corporation and over 70 companies entered into an Administrative Order on Consent with the Environmental Protection Agency (EPA) to study the same contamination. The NJDEP has also sued several other companies linked to a facility considered by the State to be the largest contributor to river contamination. In January 2009, these companies added third party defendants, including the Corporation, to that case. In June 2007, the EPA issued a draft study which evaluated six alternatives for early action, with costs ranging from $900 million to $2.3 billion for all parties. Based on adverse comments from the Corporation and others, the EPA is reevaluating its alternatives. 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, remedial costs cannot be reliably estimated at this time. Based on currently known facts and circumstances, the Corporation does not believe that this matter will result in a material liability because its terminal could not have contributed contamination along most of the river’s length and did not store or use contaminants which are of the greatest concern in the river sediments, and because there are numerous other parties who will likely share in the cost of remediation and damages.

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 proposes total penalties of $210,000. HOVENSA believes that it has good defenses against the asserted violations.

In July 2004, Hess Oil Virgin Islands Corp. (HOVIC), a wholly owned subsidiary of the Corporation, and HOVENSA, each received a letter from the Commissioner of the Virgin Islands Department of Planning and Natural Resources and Natural Resources Trustees, advising of the Trustee's intention to bring suit against HOVIC and HOVENSA under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). The letter alleges that HOVIC and HOVENSA are potentially responsible for damages to natural resources arising from releases of hazardous substances from the HOVENSA refinery, which had been operated by HOVIC until October 1998. An action was filed on May 5, 2005 in the District Court of the Virgin Islands against HOVENSA, HOVIC and other companies that operated industrial facilities on the south shore of St. Croix asserting that the defendants are liable under CERCLA and territorial statutory and common law for damages to natural resources. HOVIC and HOVENSA are continuing to vigorously defend this matter and do not believe that this matter will result in a material liability as they believe that they have strong defenses against this complaint.

The Corporation periodically receives notices from the EPA that it is a "potential responsible party" under the Superfund legislation with respect to various waste disposal sites. Under this legislation, all potentially responsible parties are jointly and severally liable. For certain sites, the EPA's claims or assertions of liability against the Corporation 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 the business or accounts of the Corporation 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.

The Corporation is from time to time involved in other judicial and administrative proceedings, including proceedings relating to other environmental matters. The Corporation 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 the financial condition, results of operations or cash flows of the Corporation.

Table of Contents

PART II

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

Stock Market Information

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

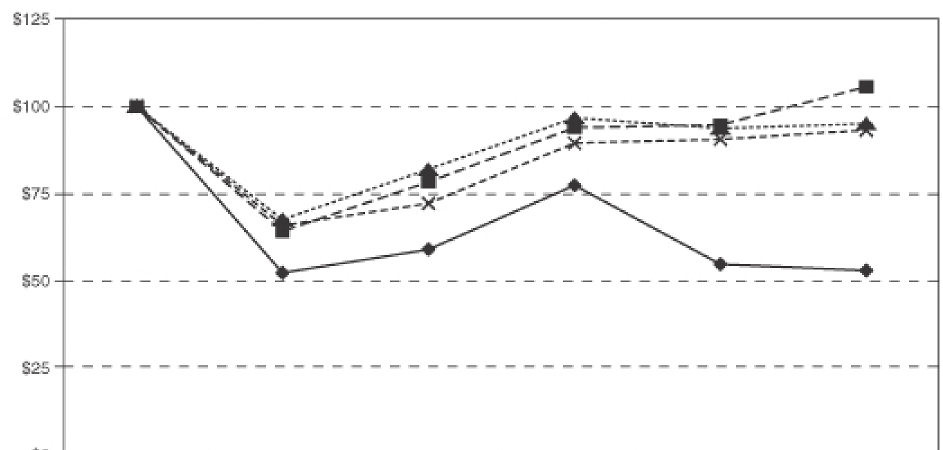
	2012		2011	
Quarter Ended	High	Low	High	Low
March 31	**$67.86**	**$54.10**	$ 87.40	$ 76.00
June 30	**60.20**	**39.67**	87.19	67.65
September 30	**57.34**	**41.94**	77.12	50.42
December 31	**55.96**	**48.20**	66.49	46.66

Performance Graph

Set forth below is a line graph comparing the five year shareholder return on a $100 investment in the Corporation’s 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,
- AMEX Oil Index, which is comprised of companies involved in various phases of the oil industry including the Corporation, and
- Proxy Peer Group comprising 16 oil and gas peer companies, including the Corporation.

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



	2007	2008	2009	2010	2011	2012
Hess Corporation	$100.00	$53.45	$60.72	$77.33	$57.74	$54.25
S&P 500	$100.00	$63.01	$79.69	$91.71	$93.62	$108.59
Amex Oil Index	$100.00	$64.52	$73.01	$85.45	$88.95	$92.60
Proxy Peer Group	$100.00	$65.84	$84.54	$95.56	$93.23	$94.25

The graph above has been amended to show the Corporation’s performance against the Proxy Peer Group, since this comparator group is used in the Proxy Statement. In future years, the AMEX Oil Index data will not be included in this graph.

Holders

At December 31, 2012, there were 4,215 stockholders (based on the number of holders of record) who owned a total of 341,527,617 shares of common stock.

Dividends

Cash dividends on common stock totaled $0.40 per share ($0.10 per quarter) during 2012, 2011 and 2010.

Equity Compensation Plans

Following is information on the Registrant's equity compensation plans at December 31, 2012:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders	12,903,000	$ 61.45	12,398,000*
Equity compensation plans not approved by security holders**	—	—	—

* *These securities may be awarded as stock options, restricted stock, performance share units or other awards permitted under the Registrant's equity compensation plan.*

** *The Corporation has a Stock Award Program pursuant to which each non-employee director annually receives approximately $175,000 in value of the Corporation's common stock. These awards are made from shares purchased by the Corporation in the open market.*

See Note 11, Share-based Compensation in the notes to the Consolidated Financial Statements for further discussion of the Corporation's equity compensation plans.

Table of Contents

Item 6. Selected Financial Data

The following is a five-year summary of selected financial data that should be read in conjunction with the Corporation's consolidated financial statements and the accompanying notes and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations included elsewhere in this Annual Report:

	2012	2011	2010	2009	2008
	(In millions, except per share amounts)				
Sales and other operating revenues					
Crude oil and natural gas liquids	**$10,332**	$ 9,065	$ 7,235	$ 5,665	$ 7,764
Natural gas (including sales of purchased gas)	**4,688**	5,526	5,723	5,894	8,800
Refined petroleum products	**18,481**	19,459	16,103	12,931	19,765
Electricity	**2,722**	2,957	3,165	3,408	3,451
Convenience store sales and other operating revenues	**1,468**	1,459	1,636	1,716	1,354
Total	**$37,691**	$ 38,466	$ 33,862	$ 29,614	$ 41,134
Net income attributable to Hess Corporation	**$ 2,025(a)**	$ 1,703(b)	$ 2,125(c)	$ 740(d)	$ 2,360(e)
Earnings per share					
Basic	**$ 5.98**	$ 5.05	$ 6.52	$ 2.28	$ 7.35
Diluted	**$ 5.95**	$ 5.01	$ 6.47	$ 2.27	$ 7.24
Total assets	**$ 43,441**	$ 39,136	$35,396	$29,465	$28,589
Total debt	**$ 8,111**	$ 6,057	$ 5,583	$ 4,467	$ 3,955
Total equity	**$21,203**	$18,592	$16,809	$ 13,528	$ 12,391
Dividends per share of common stock	**$ 0.40**	$ 0.40	$ 0.40	$ 0.40	$ 0.40

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

(b) 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.

(c) Includes after-tax income of $1,130 million relating to gains on asset sales, partially offset by after-tax charges totaling $694 million for an asset impairment, an impairment of the Corporation's equity investment in HOVENSA, dry hole expense and premiums on repurchases of fixed-rate public notes.

(d) Includes after-tax expenses totaling $104 million relating to repurchases of fixed-rate public notes, retirement benefits, employee severance costs and asset impairments, partially offset by after-tax income totaling $101 million principally relating to the resolution of a United States royalty dispute.

(e) Includes after-tax expenses totaling $26 million primarily relating to asset impairments and hurricanes in the Gulf of Mexico.

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

Overview

Hess Corporation and its subsidiaries (the Corporation or Hess) operate in two segments, Exploration and Production (E&P) and Marketing and Refining (M&R). The Corporation has made significant progress in its transformation from an integrated oil and gas company to a predominantly E&P company following the shutdown of the HOVENSA L.L.C. (HOVENSA) joint venture refinery in January 2012, and its decision in January 2013 to cease refining operations at its Port Reading facility and pursue the sale of its terminal network. Following these actions, over 90 percent of the Corporation's capital employed will be in its E&P segment. The Corporation also has shifted its E&P growth strategy from one based primarily on high impact exploration to one based on a combination of the development of unconventional resources, exploitation of existing discoveries and a smaller, more focused exploratory program. The Corporation intends to continue to pursue its strategy of transforming itself into an essentially E&P business focused on the Corporation's most promising properties and operations.

On January 29, 2013, Elliott Management Corporation (Elliott) sent a letter to Hess shareholders informing them that affiliates of Elliott beneficially own 4 percent of the outstanding common stock of the Corporation and are nominating five individuals for election as directors at the Corporation's 2013 Annual Meeting. Among other things, Elliott stated its view that Hess should (1) spin off the Corporation's Bakken assets along with the Eagle Ford and Utica acreage; (2) divest the Corporation's downstream assets and place midstream assets into a master limited partnership (MLP) or real estate investment trust (REIT) structure; and (3) divest assets from the Corporation's remaining international portfolio. The Corporation is in the process of reviewing Elliott's proposals with the Board and its advisors and intends to respond in the near future.

Net income in 2012 was $2,025 million compared with $1,703 million in 2011 and $2,125 million in 2010. Diluted earnings per share were $5.95 in 2012 compared with $5.01 in 2011 and $6.47 in 2010. A table of items affecting comparability of earnings between periods is shown on page 22.

Exploration and Production

The Corporation's total proved reserves were 1,553 million barrels of oil equivalent (boe) at December 31, 2012 compared with 1,573 million boe at December 31, 2011 and 1,537 million boe at December 31, 2010.

E&P earnings were $2,212 million in 2012, $2,675 million in 2011 and $2,736 million in 2010. Excluding items affecting comparability of earnings between periods, E&P net income was $2,256 million, $2,431 million and $2,004 million for 2012, 2011 and 2010, respectively. Average realized crude oil selling prices were $86.94 per barrel in 2012, $89.99 in 2011 and $66.20 in 2010, including the impact of hedging. Average realized natural gas selling prices were $6.16 per mcf in 2012, $5.96 in 2011 and $5.63 in 2010. Production averaged 406,000 barrels of oil equivalent per day (boepd) in 2012, 370,000 boepd in 2011 and 418,000 boepd in 2010. The Corporation currently expects total worldwide production to average between 375,000 boepd and 390,000 boepd in 2013. This forecast assumes Russian operations remain in the portfolio for the full year.

The following is an update of significant E&P activities during 2012:

- In North Dakota, net production from the Bakken oil shale play averaged 56,000 boepd during 2012, an increase of 87% from 30,000 boepd in 2011. In the fourth quarter of 2012, the Corporation substantially completed "held by production" drilling in the Bakken and is transitioning to pad drilling, which involves sequentially drilling a number of wells on a pad followed by sequential completion of the wells. This pad drilling process is expected to lead to a temporary flattening of the Bakken production profile until mid-2013. Bakken production is expected to average between 64,000 boepd and 70,000 boepd for the full year of 2013, with most of the increase from 2012 expected to occur in the second half of the year.
- At the Valhall Field, a multi-year redevelopment project was advanced in 2012 and completed in early 2013. The project included the installation of a new production, utilities and accommodation platform and expansion of gross production capacity to 120,000 barrels of liquids per day and 143,000 mcf of natural gas per day. In July 2012, the field was shut-in to complete the installation and commissioning of the new facilities and production resumed in January 2013.
- The Corporation completed the sale of its interests in the Schiehallion Field (Hess 16%), the Bittern Field (Hess 28%) and related assets in the United Kingdom North Sea, and the Snohvit Field (Hess 3%), offshore Norway, for total cash proceeds of $843 million. These transactions resulted in pre-tax gains totaling $584 million ($557 million after income taxes). These assets were producing at an aggregate net rate of approximately 15,000 boepd at the time of sale and had a total of 83 million boe of proved reserves.

- In October, the Corporation also announced that it had reached an agreement to sell its interests in the Beryl fields in the United Kingdom North Sea. These assets were producing at an aggregate net rate of approximately 15,000 boepd at the time of sale and had a total of 21 million boe of proved reserves. The sale was completed in January 2013 for cash proceeds of approximately $440 million.
- In September, the Corporation reached an agreement to sell its interests in the Azeri-Chirag-Guneshli (ACG) fields (Hess 3%) in Azerbaijan and its interest in the associated Baku-Tbilisi-Ceyhan (BTC) pipeline (Hess 2%) for approximately $1 billion, subject to normal closing adjustments. The transaction, which is expected to close in the first quarter of 2013, is subject to government and regulatory approvals.
- In June, the Corporation signed agreements with its partner to develop nine discovered natural gas fields in the North Malay Basin, located offshore Peninsular Malaysia. The Corporation will have a 50% interest and is the operator. First production is forecast to commence from an early production system in the second half of 2013.
- During the third quarter of 2012, the Corporation signed an exchange agreement with the partners of Green Canyon Block 512 that contains the Knotty Head discovery and is in the same reservoir as the Corporation's Pony discovery on the adjacent Block 468. Under this agreement, the Corporation was appointed operator and has a 20% working interest in the blocks, now collectively referred to as Stampede. Field development planning is progressing and the project is targeted for sanction in 2014.
- During the year, the Corporation completed four successful exploration wells on the Deepwater Tano Cape Three Points block, offshore Ghana. In early 2013, the Corporation completed two additional successful wells, resulting in a total of seven consecutive successful exploration wells. Based on the results of these wells, the Corporation plans to submit an appraisal plan to the Ghanaian government for approval on or before June 2, 2013. In parallel, the Corporation has begun pre-development studies on the block.

Marketing and Refining

Results from M&R activities were earnings of $231 million in 2012, a loss of $584 million in 2011 and a loss of $231 million in 2010. Excluding items affecting comparability of earnings between periods, M&R earnings were $160 million in 2012, a loss of $59 million in 2011 and earnings of $58 million in 2010. In January 2012, HOVENSA shut down its refinery in St. Croix, U.S. Virgin Islands. The Corporation and its joint venture partner plan to pursue the sale of HOVENSA, while the complex is operated as an oil storage terminal. In January 2013, the Corporation announced its decision to cease refining operations in February at its Port Reading facility and pursue the sale of its terminal network.

Liquidity and Capital and Exploratory Expenditures

Net cash provided by operating activities was $5,660 million in 2012, $4,984 million in 2011 and $4,530 million in 2010. At December 31, 2012, cash and cash equivalents totaled $642 million, an increase from $351 million at December 31, 2011. Total debt was $8,111 million at December 31, 2012 and $6,057 million at December 31, 2011. The Corporation's debt to capitalization ratio at December 31, 2012 was 27.7% compared with 24.6% at the end of 2011.

Capital and exploratory expenditures were as follows:

	2012	2011	2010
		(In millions)	
Exploration and Production			
United States	**$4,763**	$ 4,305	$ 2,935
International	**3,383**	3,039	2,822
Total Exploration and Production	**8,146**	7,344	5,757
Marketing, Refining and Corporate	**119**	118	98
Total capital and exploratory expenditures	**$ 8,265**	$7,462	$5,855
Exploration expenses charged to income included above:			
United States	**$ 142**	$ 197	$ 154
International	**328**	259	209
Total exploration expenses charged to income included above	**$ 470**	$ 456	$ 363

The Corporation anticipates investing $6.8 billion in capital and exploratory expenditures in 2013, substantially all of which is targeted for E&P operations.

Table of Contents

Consolidated Results of Operations

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

	2012	2011	2010
		(In millions, except per share amounts)	
Exploration and Production	**$ 2,212**	$ 2,675	$ 2,736
Marketing and Refining	**231**	(584)	(231)
Corporate	**(158)**	(154)	(159)
Interest expense	**(260)**	(234)	(221)
Net income attributable to Hess Corporation	**$ 2,025**	$ 1,703	$ 2,125
Net income per share — diluted	**$ 5.95**	$ 5.01	$ 6.47

The following table summarizes, on an after-tax basis, items of income (expense) that are included in net income and affect comparability between periods. The items in the table below are explained on pages 25 through 27.

	2012	2011	2010
		(In millions)	
Exploration and Production	**$ (44)**	$ 244	$ 732
Marketing and Refining	**71**	(525)	(289)
Corporate	**—**	—	(7)
	$ 27	$ (281)	$ 436

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.

Comparison of Results

Exploration and Production

Following is a summarized income statement of the Corporation's E&P operations:

	2012	2011	2010
		(In millions)	
Sales and other operating revenues*	**$ 10,893**	$ 10,047	$ 8,744
Gains on asset sales	**584**	446	1,208
Other, net	**99**	18	25
Total revenues and non-operating income	**11,576**	10,511	9,977
Costs and expenses			
Production expenses, including related taxes	**2,752**	2,352	1,924
Exploration expenses, including dry holes and lease impairment	**1,070**	1,195	865
General, administrative and other expenses	**314**	313	281
Depreciation, depletion and amortization	**2,853**	2,305	2,222
Asset impairments	**582**	358	532
Total costs and expenses	**7,571**	6,523	5,824
Results of operations before income taxes	**4,005**	3,988	4,153
Provision for income taxes	**1,793**	1,313	1,417
Results of operations attributable to Hess Corporation	**$ 2,212**	$ 2,675	$ 2,736

** Amounts differ from E&P operating revenues in Note 18, Segment Information in the notes to the Consolidated Financial Statements primarily due to the exclusion of sales of hydrocarbons purchased from third parties.*

After considering the E&P items affecting comparability of earnings between periods in the table on page 25, the remaining changes in E&P earnings are primarily attributable to changes in selling prices, production and sales volumes, operating costs, depreciation, depletion and amortization, exploration expenses and income taxes, as discussed below.

Selling Prices: Lower average realized selling prices, primarily from crude oil and natural gas liquids, decreased E&P revenues by approximately $380 million in 2012 compared with the corresponding period in 2011. Higher average selling prices increased E&P revenues by approximately $2,400 million in 2011 compared with 2010.

The Corporation's average selling prices were as follows:

	2012	2011	2010
Crude oil — per barrel (including hedging)			
United States	**$ 92.32**	$ 98.56	$ 75.02
Europe	**74.14**	80.18	58.11
Africa	**89.02**	88.46	65.02
Asia	**107.45**	111.71	79.23
Worldwide	**86.94**	89.99	66.20
Crude oil — per barrel (excluding hedging)			
United States	**$ 93.96**	$ 98.56	$ 75.02
Europe	**75.06**	80.18	58.11
Africa	**110.92**	110.28	78.31
Asia	**109.35**	111.71	79.23
Worldwide	**93.70**	95.60	71.40
Natural gas liquids — per barrel			
United States	**$ 40.75**	$ 58.59	$ 47.92
Europe	**78.43**	75.49	59.23
Asia	**77.92**	72.29	63.50
Worldwide	**47.81**	62.72	50.49
Natural gas — per mcf			
United States	**$ 2.09**	$ 3.39	$ 3.70
Europe	**9.50**	8.79	6.23
Asia and other	**6.90**	6.02	5.93
Worldwide	**6.16**	5.96	5.63

In October 2008, the Corporation closed Brent crude oil hedges covering 24,000 barrels per day from 2009 through 2012 by entering into offsetting contracts with the same counterparty. The deferred after-tax losses, as of the date the hedge positions were closed, were recorded in earnings as the contracts matured. The Corporation also entered into Brent crude oil hedges using fixed-price swap contracts to hedge 120,000 boepd of crude oil sales volumes for the full year of 2012 at an average price of $107.70 per barrel. Crude oil hedges reduced E&P earnings by $431 million ($688 million before income taxes) in 2012, $327 million ($517 million before income taxes) in 2011 and $338 million ($533 million before income taxes) in 2010. Both of these hedge programs matured as of December 31, 2012. In January and February 2013, the Corporation entered into Brent crude oil hedges using fixed-price swap contracts to hedge 90,000 boepd of crude oil sales volumes for the remainder of the calendar year at an average price of approximately $109.70 per barrel.

Production and Sales Volumes: The Corporation's crude oil and natural gas production was 406,000 boepd in 2012, 370,000 boepd in 2011 and 418,000 boepd in 2010. Approximately 75% in 2012, 72% in 2011 and 73% in 2010 of the Corporation's production was from crude oil and natural gas liquids. The Corporation currently expects total worldwide production to average between 375,000 boepd and 390,000 boepd in 2013. This forecast assumes Russian operations remain in the portfolio for the full year.

Table of Contents

The Corporation's net daily worldwide production was as follows:

	2012	2011	2010
		(In thousands)	
Crude oil — barrels per day			
United States			
Bakken	**47**	26	12
Other Onshore	**13**	11	11
Total Onshore	**60**	37	23
Offshore	**48**	44	52
Total United States	**108**	81	75
Europe	**84**	89	88
Africa	**75**	66	113
Asia	**17**	13	13
Total	**284**	249	289
Natural gas liquids — barrels per day			
United States			
Bakken	**5**	2	2
Other Onshore	**5**	5	5
Total Onshore	**10**	7	7
Offshore	**6**	6	7
Total United States	**16**	13	14
Europe	**2**	3	3
Asia	**1**	1	1
Total	**19**	17	18
Natural gas — mcf per day			
United States			
Bakken	**27**	13	9
Other Onshore	**27**	26	29
Total Onshore	**54**	39	38
Offshore	**65**	61	70
Total United States	**119**	100	108
Europe	**43**	81	134
Asia and other	**454**	442	427
Total	**616**	623	669
Barrels of oil equivalent — per day*	**406**	370	418

* *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. See the average selling prices table.*

United States: Crude oil, natural gas liquids and natural gas production in the United States was higher in 2012 compared with 2011, primarily due to new wells in the Bakken oil shale play. In the second quarter of 2012, production restarted from a well at the Llano Field after a successful workover of the well, which had been shut-in for mechanical reasons since the first quarter of 2011. Crude oil production was higher in 2011 compared with 2010, primarily due to new wells in the Bakken oil shale play, partly offset by lower production due to the shut-in well at the Llano Field. Natural gas production was lower in 2011 compared with 2010, primarily due to this shut-in well at the Llano Field.

Europe: Crude oil production in 2012 was lower than 2011, primarily due to downtime at the Valhall Field in Norway which was shut-in from mid-July 2012 until January 2013 in order to complete a field redevelopment project. Crude oil production in 2011 was comparable to 2010, as higher production from Norway and Russia was largely offset by lower production from the Corporation's United Kingdom North Sea assets. Natural gas production was lower in 2012 compared with 2011, primarily due to the sale of the Snohvit Field, offshore Norway, in January 2012, downtime at the Valhall Field as noted above and natural decline at the Beryl Field in the United Kingdom North Sea. Natural gas production was lower in 2011 compared with 2010, primarily due to the sale in February 2011 of certain natural gas producing assets in the United Kingdom North Sea.

Africa: Crude oil production increased in 2012 compared with 2011, mainly due to the resumption of production in Libya, partly offset by lower production in Equatorial Guinea due to downtime and natural field decline. Following the lifting of the economic sanctions imposed in response to civil unrest, the Corporation's production in Libya resumed during the fourth quarter of 2011 after being shut-in from the first quarter of 2011. Crude oil production decreased in 2011 compared with 2010 due to the suspension of production in Libya, the exchange in September 2010 of the Corporation's interests in Gabon for increased interests in Norway, lower production entitlement in Equatorial Guinea and Algeria as a result of higher selling prices and natural decline in Equatorial Guinea.

Asia and other: Natural gas production in 2012 was higher than 2011, primarily due to new wells at the Pangkah Field in Indonesia and a full year's contribution from the Gajah Baru Complex at the Natuna A Field in Indonesia, which commenced production in the fourth quarter of 2011. Natural gas production in 2011 was higher than 2010, primarily due to higher nominations at Block PM301 in Malaysia and first production from the Gajah Baru Complex.

Sales volumes: Higher sales volumes and other operating revenues increased revenue by approximately $1,225 million in 2012 compared with 2011, and lower sales volumes and other operating revenues decreased revenue by approximately $1,100 million in 2011 compared with 2010.

Operating Costs and Depreciation, Depletion and Amortization: Cash operating costs, consisting of production expenses and general and administrative expenses, increased by $401 million in 2012 compared with 2011 and increased by $460 million in 2011 compared with 2010. The increase in 2012 reflects higher production taxes as a result of increased production volumes at the Bakken oil shale play and in Russia, together with higher operating and maintenance costs at the Valhall Field in Norway, the Llano Field in the United States and the Bakken. The increase in costs in 2011 compared to 2010 was primarily due to higher production taxes as a result of higher selling prices, together with higher operating and maintenance expenses, mainly in Norway and the Bakken.

Depreciation, depletion and amortization charges increased by $548 million in 2012 and $83 million in 2011, compared with the corresponding amounts in prior years. The increase in 2012 was primarily due to higher volumes and per barrel costs. The increase in 2011 was primarily due to higher per barrel costs, reflecting higher finding and development costs. In addition, the higher per barrel rates in 2012 and 2011 were largely due to greater production contribution from unconventional assets.

Excluding items affecting comparability of earnings between periods, cash operating costs per barrel of oil equivalent were $20.63 in 2012, $19.71 in 2011 and $14.45 in 2010. Depreciation, depletion and amortization costs per barrel of oil equivalent were $19.20 in 2012, $17.06 in 2011 and $14.56 in 2010. For 2013, cash operating costs are estimated to be in the range of $21.00 to $22.00 per barrel and depreciation, depletion and amortization costs are estimated to be in the range of $19.00 to $20.00 per barrel, resulting in total unit costs of $40.00 to $42.00 per barrel of oil equivalent.

Exploration Expenses: Exploration expenses decreased in 2012 compared to 2011, primarily due to lower dry hole expenses and lease amortization. Dry hole expenses in 2012 included amounts associated with two exploration wells, Ness Deep in the Gulf of Mexico and Ajek-1, offshore Indonesia. Exploration expenses increased in 2011 from 2010, mainly due to higher dry hole expenses, which included amounts relating to two exploration wells on the Semai V Block, offshore Indonesia, and a well in the North Red Sea Block 1, offshore Egypt.

Income Taxes: Excluding the impact of items affecting comparability of earnings between periods, the effective income tax rates for E&P operations were 45% in 2012, 38% in 2011 and 44% in 2010. The increase in the effective income tax rate in 2012 compared with 2011 was predominantly due to the resumption of Libyan operations. The effective income tax rate for E&P operations in 2013 is estimated to be in the range of 46% to 50%.

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

	Before Income Taxes			After Income Taxes		
	2012	**2011**	**2010**	**2012**	**2011**	**2010**
			(In millions)			
Gains on asset sales	**$ 584**	$ 446	$1,208	**$ 557**	$ 413	$1,130
Asset impairments	**(582)**	(358)	(532)	**(344)**	(140)	(334)
Dry hole and other expenses	**(86)**	—	(101)	**(56)**	—	(64)
Income tax adjustments	**—**	—	—	**(201)**	(29)	—
	$ (84)	$ 88	$ 575	**$ (44)**	$ 244	$ 732

2012: The Corporation completed the sale of its interests in the Schiehallion Field (Hess 16%), the Bittern Field (Hess 28%) and related assets, which are all located in the United Kingdom North Sea, and the Snohvit Field (Snohvit) (Hess 3%), offshore Norway, for total cash proceeds of $843 million. These transactions resulted in pre-tax gains totaling $584 million ($557 million after income taxes). These assets were producing at an aggregate net rate of approximately 15,000 boepd at the time of sale and had a total of 83 million boe of proved reserves. See also Note 2, Dispositions in the notes to the Consolidated Financial Statements.

During 2012, E&P recorded three asset impairment charges totaling $582 million ($344 million after income taxes). As a result of a competitive bidding process, the Corporation obtained additional information relating to the fair value of its interests in the Cotulla area of the Eagle Ford Shale in Texas in February 2013. Based on this information and management's anticipated plan for the assets as of December 31, 2012, the Corporation recorded an impairment charge of $315 million ($192 million after income taxes). The Corporation also recorded charges of $208 million ($116 million after income taxes) related to increases in estimated abandonment liabilities primarily for non-producing properties which resulted in the book value of the properties exceeding their fair value. In addition, the Corporation recorded a charge of $59 million ($36 million after income taxes) in the second quarter related to the disposal of certain Eagle Ford properties as part of an asset exchange with its joint venture partner.

During the third quarter of 2012, the Corporation decided to cease further development and appraisal activities in Peru. As a result, the Corporation recorded exploration expenses totaling $86 million ($56 million after income taxes) to write off its exploration assets in the country.

In July 2012, the government of the United Kingdom changed the supplementary income tax rate applicable to deductions for dismantlement expenditures to 20% from 32%. As a result, the Corporation recorded a one-time charge in the third quarter of 2012 of $115 million for deferred taxes related to asset retirement obligations in the United Kingdom. In the fourth quarter of 2012, the Corporation recorded an income tax charge of $86 million for a disputed application of an international tax treaty.

2011: The Corporation completed the sale of its interests in certain natural gas producing assets in the United Kingdom North Sea, the Snorre Field (Hess 1%), offshore Norway, and the Cook Field (Hess 28%) in the United Kingdom North Sea for total cash proceeds of $490 million. These disposals resulted in pre-tax gains totaling $446 million ($413 million after income taxes). These assets had an aggregate net productive capacity of approximately 17,500 boepd at the time of sale.

In the third quarter of 2011, the Corporation recorded asset impairment charges of $358 million ($140 million after income taxes) related to increases in the Corporation's estimated abandonment liabilities primarily for non-producing properties in the United Kingdom North Sea which resulted in the book value of the properties exceeding their fair value.

In July 2011, the United Kingdom increased the supplementary tax rate on petroleum operations to 32% from 20% with an effective date of March 24, 2011. As a result, the Corporation recorded a charge of $29 million to increase deferred tax liabilities in the United Kingdom.

2010: The Corporation completed the exchange of its interests in Gabon and the Clair Field in the United Kingdom for additional interests of 28% and 25%, respectively, in the Valhall and Hod fields in Norway. This non-monetary transaction, which was recorded at fair value, resulted in a pre-tax gain of $1,150 million ($1,072 million after income taxes). The Corporation completed the sale of its interest in the Jambi Merang natural gas development project in Indonesia (Hess 25%) for cash proceeds of $183 million. The transaction resulted in a gain of $58 million.

The Corporation recorded an asset impairment charge of $532 million ($334 million after income taxes) to fully impair the carrying value of its 55% interest in the West Mediterranean Block 1 concession (West Med Block), located offshore Egypt when the Corporation and its partners notified the Egyptian authorities of their decision to cease exploration activities and to relinquish a significant portion of the block. The West Med Block was relinquished in 2011. The Corporation also recorded $101 million ($64 million after income taxes) of dry hole expenses related to previously suspended well costs on the West Med Block offshore Egypt and Block BM-S-22 offshore Brazil, both of which were drilled prior to 2010.

Marketing and Refining

Results from M&R activities were earnings of $231 million in 2012, a loss of $584 million in 2011 and a loss of $231 million in 2010. Excluding items affecting comparability of earnings between periods in the table below, M&R results were earnings of $160 million in 2012, a loss of $59 million in 2011 and earnings of $58 million in 2010.

M&R Sales and other operating revenue were $25,520 million, $27,936 million and $24,885 million in 2012, 2011 and 2010, respectively. In 2012, Sales and other operating revenue decreased compared with 2011, reflecting lower refined petroleum product sales volumes together with lower gas and electricity selling prices. In 2011, Sales and other operating revenues increased compared with 2010, primarily due to higher refined petroleum product selling prices partially offset by the effect of lower refined petroleum product sales volumes.

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

	Before Income Taxes			After Income Taxes		
	2012	2011	2010	2012	2011	2010
	(In millions)					
LIFO inventory liquidation	**$ 165**	$ —	$ —	**$ 104**	$ —	$ —
Asset impairments and other charges	**(43)**	—	—	**(33)**	—	—
Charges related to equity investment in HOVENSA	**—**	(875)	(300)	**—**	(525)	(289)
	$ 122	$ (875)	$ (300)	**$ 71**	$ (525)	$ (289)

In 2012, the Corporation recorded income of $165 million ($104 million after income taxes) from the partial liquidation of last-in, first-out (LIFO) inventories. The Corporation also recorded charges of $43 million ($33 million after income taxes) for asset impairments to certain marketing properties and other charges.

As a result of continued substantial operating losses and unsuccessful efforts to improve operating performance by reducing refining capacity, HOVENSA prepared an impairment analysis as of December 31, 2011, which concluded that undiscounted future cash flows would not recover the carrying value of its long-lived assets, and recorded an impairment charge and other charges related to the decision to shut down the refinery. In 2011, the Corporation recorded a charge of $875 million ($525 million after income taxes) due to the impairment recorded by HOVENSA and other charges associated with its decision to shut down the refinery. The Corporation's share of the impairment related losses recorded by HOVENSA represented an amount equivalent to the Corporation's financial support to HOVENSA at December 31, 2011, its planned future funding commitments for costs related to the refinery shutdown, and a charge of $135 million for the write-off of related assets held by the subsidiary which owns the Corporation's investment in HOVENSA. A deferred income tax benefit of $350 million, consisting primarily of U.S. income taxes, was recorded on the Corporation's share of HOVENSA's impairment and refinery shutdown related charges.

In December 2010, the Corporation recorded an impairment charge of $300 million before income taxes ($289 million after income taxes) to reduce the carrying value of its equity investment in HOVENSA to fair value.

Marketing: Marketing operations, which consist principally of retail gasoline and energy marketing activities, generated earnings of $209 million in 2012, $185 million in 2011 and $215 million in 2010. Excluding items affecting comparability of earnings between periods, Marketing earnings were $138 million in 2012, $185 million in 2011 and $215 million in 2010. The decrease in earnings over the period from 2010 to 2012 was primarily due to lower margins and lower refined product sales volumes.

The table below summarizes marketing sales volumes:

	2012	2011	2010
Refined petroleum product sales (thousands of barrels per day)	**389**	430	471
Natural gas (thousands of mcf per day)	**2,300**	2,200	2,000
Electricity (megawatts round the clock)	**4,500**	4,400	4,100

Refining: Refining results consist of the Corporation's share of HOVENSA's losses, together with the results of Port Reading and other operating activities. Refining generated earnings of $28 million in 2012, a loss of $728 million in 2011 and a loss of $445 million in 2010.

The Corporation did not record any incremental equity income or loss for HOVENSA in 2012, as the Corporation fully accrued its estimated funding commitments for HOVENSA's refinery shutdown at December 31, 2011. Excluding items affecting comparability of earnings between periods, the Corporation's share of HOVENSA's results was a loss of $198 million in 2011 and a loss of $137 million ($222 million before income taxes) in 2010, reflecting weak refining margins. U.S. Virgin Island income taxes were not recorded on the Corporation's share of HOVENSA's 2011 results due to cumulative operating losses.

Table of Contents

Other after-tax refining results, principally from Port Reading operations, generated earnings of $28 million in 2012, a loss of $5 million in 2011 and a loss of $19 million in 2010. The Port Reading refining facility has a capacity of 70,000 barrels per day and the facility operated at a rate of 59,000 barrels per day in 2012, 63,000 barrels per day in 2011 and 55,000 barrels per day in 2010. In January 2013, the Corporation announced its decision to cease refining operations in February at its Port Reading facility.

The Corporation has a 50% voting interest in a consolidated partnership that trades energy commodities and energy derivatives. The Corporation also takes trading positions for its own account. The Corporation's after-tax results from trading activities, including its share of the results of the trading partnership, amounted to losses of $6 million in 2012, $41 million in 2011 and $1 million in 2010.

Marketing expenses decreased in 2012 compared with 2011 principally reflecting lower retail credit card fees. Marketing expenses increased in 2011 compared with 2010 reflecting higher retail credit card fees, maintenance, environmental and employee related expenses.

The Corporation's future M&R earnings may be impacted by supply and demand factors, volatility in margins, credit risks, the effects of weather, competitive industry conditions, political risk, environmental risk and catastrophic risk. For a more comprehensive description of the risks that may affect the Corporation's M&R business, see Item 1A. Risk Factors Related to Our Business and Operations.

Corporate

The following table summarizes corporate expenses:

	2012	2011	2010
		(In millions)	
Corporate expenses (excluding items affecting comparability)	**$ 262**	$ 260	$256
Income taxes (benefits)	**(104)**	(106)	(104)
Net corporate expenses, after-tax	**158**	154	152
Items affecting comparability of earnings between periods, after-tax	**—**	—	7
Total corporate expenses, after-tax	**$ 158**	$ 154	$159

Corporate expenses were comparable in 2012, 2011 and 2010. After-tax corporate expenses in 2013 are estimated to be in the range of $160 million to $170 million.

Interest Expense

The following table summarizes interest expense:

	2012	2011	2010
		(In millions)	
Total interest incurred	**$ 447**	$ 396	$366
Less: Capitalized interest	**(28)**	(13)	(5)
Interest expense before income taxes	**419**	383	361
Income taxes (benefits)	**(159)**	(149)	(140)
Total interest expense, after-tax	**$ 260**	$ 234	$221

The increase in interest expense incurred in 2012 and 2011 principally reflects higher average debt and bank facility fees. Capitalized interest increased in 2012 compared with 2011, primarily due to the sanctioning of the Tubular Bells project in September 2011. After-tax interest expense in 2013 is expected to be in the range of $255 million to $265 million.

Liquidity and Capital Resources

The following table sets forth certain relevant measures of the Corporation's liquidity and capital resources at December 31:

	2012	2011
	(In millions)	
Cash and cash equivalents	**$ 642**	$ 351
Short-term debt and current maturities of long-term debt	**$ 787**	$ 52
Total debt	**$ 8,111**	$ 6,057
Total equity	**$21,203**	$18,592
Debt to capitalization ratio*	**27.7%**	24.6%

** Total debt as a percentage of the sum of total debt plus equity.*

Cash Flows

The following table sets forth a summary of the Corporation's cash flows:

	2012	2011	2010
		(In millions)	
Net cash provided by (used in):			
Operating activities	**$ 5,660**	$ 4,984	$ 4,530
Investing activities	**(7,051)**	(6,566)	(5,259)
Financing activities	**1,682**	325	975
Net increase (decrease) in cash and cash equivalents	**$ 291**	$ (1,257)	$ 246

***Operating Activities*:** Net cash provided by operating activities amounted to $5,660 million in 2012 compared with $4,984 million in 2011, reflecting higher operating earnings and increases in cash flows from changes in working capital. Operating cash flow increased to $4,984 million in 2011 from $4,530 million in 2010 principally reflecting higher operating earnings partially offset by a decrease in cash flows from changes in working capital.

Investing Activities: The following table summarizes the Corporation's capital expenditures:

	2012	2011	2010
		(In millions)	
Exploration and Production			
Exploration	**$ 619**	$ 869	$ 552
Production and development	**6,790**	4,673	2,592
Acquisitions (including leaseholds)	**267**	1,346	2,250
	7,676	6,888	5,394
Marketing, Refining and Corporate	**119**	118	98
Total	**$7,795**	$ 7,006	$ 5,492

The increased spend on capital expenditures in 2012 primarily reflected additional spending at the Bakken oil shale play as a result of drilling new wells, higher working interest wells and increased spending on field infrastructure projects. Capital expenditures in 2011 included acquisitions of approximately $800 million for 195,000 net acres in the Utica Shale play in Ohio, $214 million for interests in two blocks in the Kurdistan Region of Iraq and $116 million for an additional 4% interest in the South Arne Field in Denmark. Capital expenditures in 2010 included acquisitions of 167,000 net acres in the Bakken oil shale play in North Dakota from TRZ Energy, LLC for $1,075 million in cash and additional interests of 8% and 13% in the Valhall and Hod fields, respectively, for $507 million in cash.

The Corporation received total proceeds from the sale of assets in the E&P segment of $843 million in 2012, $490 million in 2011 and $183 million in 2010.

Financing Activities: During 2012, the Corporation borrowed a net of $1,845 million from available credit facilities, which consisted of borrowings of $758 million from its syndicated revolving credit facility, $890 million from its short-term credit facilities and $250 million from its asset-backed credit facility, partially offset by net repayments of other debt of $53 million. During 2011, net proceeds from borrowings on available credit facilities were $422 million. During 2010, net proceeds from borrowings were $1,098 million, including the August 2010 issuance of $1,250 million of 30-year fixed-rate public notes with a coupon of 5.6% scheduled to mature in 2041. In January 2010, the Corporation completed the repurchase of the remaining $116 million of fixed-rate public notes that were scheduled to mature in 2011.

Total common stock dividends paid were $171 million in 2012, $136 million in 2011 and $131 million in 2010. In 2012, the Corporation made five quarterly common stock dividend payments as a result of accelerating payment of the fourth quarter 2012 dividend, which historically would have been paid in the first quarter of 2013. The Corporation received net proceeds from the exercise of stock options, including related income tax benefits of $11 million, $88 million and $54 million in 2012, 2011 and 2010, respectively.

Future Capital Requirements and Resources

The Corporation anticipates investing a total of approximately $6.8 billion in capital and exploratory expenditures during 2013, substantially all of which is targeted for E&P operations. This reflects an 18 percent reduction from the 2012 total of $8.3 billion. The decrease is substantially attributable to a reduced level of spend in the Bakken driven by lower drilling and completion costs and decreased investments in infrastructure projects.

During 2012, the Corporation funded its capital spending through cash flows from operations, incremental borrowings and proceeds from asset sales. The Corporation had a cash flow deficit of approximately $2.5 billion in 2012 and the projected deficit for 2013 is expected to moderate versus 2012 based on current commodity prices. During 2012, the Corporation announced asset sales totaling $2.4 billion, of which cash proceeds of $843 million were received in 2012 and approximately $440 million were received in January 2013. The Corporation is also pursuing the sale of its Russian operations, Eagle Ford assets and its terminal network. The Corporation expects to fund its 2013 capital expenditures and ongoing operations, including dividends, pension contributions and debt repayments with existing cash on-hand, cash flows from operations and proceeds from asset sales.

Crude oil and natural gas prices are volatile and difficult to predict. In addition, unplanned increases in the Corporation's capital expenditure program could occur. If conditions were to change, such as a significant decrease in commodity prices or an unexpected increase in capital expenditures, the Corporation would take steps to protect its financial flexibility and may pursue other sources of liquidity, including the issuance of debt securities, the issuance of equity securities, and/or further asset sales.

See Overview on page 20 for a discussion of Elliott Management Corporation.

The table below summarizes the capacity, usage, and available capacity of the Corporation's borrowing and letter of credit facilities at December 31, 2012:

	Expiration Date	Capacity	Borrowings	Letters of Credit Issued	Total Used	Available Capacity
				(In millions)		
Revolving credit facility	April 2016	$ 4,000	$ 758	$ —	$ 758	$ 3,242
Asset-backed credit facility	July 2013 (a)	642	600	—	600	42
Committed lines	Various (b)	2,730	500	463	963	1,767
Uncommitted lines	Various (b)	773	490	283	773	—
Total		$8,145	$ 2,348	$ 746	$ 3,094	$5,051

(a) Total capacity of $1 billion subject to the amount of eligible receivables posted as collateral.
(b) Committed and uncommitted lines have expiration dates through 2014.

The Corporation has a $4 billion syndicated revolving credit facility that matures in April 2016. This facility can be used for borrowings and letters of credit. Borrowings on the facility bear interest at 1.25% above the London Interbank Offered Rate. A fee of 0.25% per annum is also payable on the amount of the facility. The interest rate and facility fee are subject to adjustment if the Corporation's credit rating changes.

The Corporation has a 364-day asset-backed credit facility secured by certain accounts receivable from its M&R operations. Under the terms of this financing arrangement, the Corporation has the ability to borrow or issue letters of credit of up to $1 billion subject to the availability of sufficient levels of eligible receivables. At December 31, 2012, outstanding borrowings under this facility of $600 million were collateralized by a total of approximately $1,050 million of accounts receivable, which are held by a wholly-owned subsidiary. These receivables are only available to pay the general obligations of the Corporation after satisfaction of the outstanding obligations under the asset-backed facility.

On February 27, 2012, the Corporation filed a shelf registration statement with the Securities and Exchange Commission under which it may issue additional debt securities, warrants, common stock or preferred stock.

The Corporation's long-term debt agreements contain a financial covenant that restricts the amount of total borrowings and secured debt. At December 31, 2012, the Corporation is permitted to borrow up to an additional $27.2 billion for the construction or acquisition of assets. The Corporation has the ability to borrow up to an additional $4.9 billion of secured debt at December 31, 2012.

The Corporation's $746 million in letters of credit outstanding at December 31, 2012 were primarily issued to satisfy margin requirements. See also Note 20, Risk Management and Trading Activities in the notes to the Consolidated Financial Statements.

Credit Ratings

There are three major credit rating agencies that rate the Corporation's debt. All three agencies have currently assigned an investment grade rating with a stable outlook to the Corporation's debt. The interest rates and facility fees charged on some of the Corporation's credit facilities, as well as margin requirements from risk management and trading counterparties, are subject to adjustment if the Corporation's credit rating changes.

Contractual Obligations and Contingencies

The following table shows aggregate information about certain contractual obligations at December 31, 2012:

		Payments Due by Period			
	Total	2013	2014 and 2015	2016 and 2017	Thereafter
			(In millions)		
Total debt*	$ 8,111	$ 787	$ 530	$ 1,617	$ 5,177
Operating leases	2,843	700	831	252	1,060
Purchase obligations					
Supply commitments	5,702	4,664	723	122	193
Capital expenditures and other investments	3,117	1,558	1,015	407	137
Operating expenses	2,582	1,387	558	314	323
Other liabilities	3,972	529	749	392	2,302

** At December 31, 2012, the Corporation's debt bears interest at a weighted average rate of 5.3%.*

Supply commitments include term purchase agreements at market prices for a portion of the gasoline necessary to supply the Corporation's retail marketing system. In addition, the Corporation has commitments to purchase refined petroleum products, natural gas and electricity to supply contracted customers in its energy marketing business. These commitments were computed based predominately on year-end market prices.

The table also reflects future capital expenditures, including the portion of the Corporation's planned $6.8 billion capital investment program for 2013 that was contractually committed at December 31, 2012. Obligations for operating expenses include commitments for transportation, seismic purchases, oil and gas production expenses and other normal business expenses. Other long-term liabilities reflect contractually committed obligations in the Consolidated Balance Sheet at December 31, 2012, including asset retirement obligations, pension plan liabilities and estimates for uncertain income tax positions.

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

The Corporation has a contingent purchase obligation to acquire the remaining interest in WilcoHess, a retail gasoline station joint venture. This contingent obligation, which expires in April 2014, was approximately $210 million at December 31, 2012.

The Corporation is contingently liable under $141 million of letters of credit of other entities directly related to its business at December 31, 2012.

Off-balance Sheet Arrangements

The Corporation has leveraged leases not included in its Consolidated Balance Sheet, primarily related to retail gasoline stations that the Corporation operates. The net present value of these leases is $342 million at December 31, 2012 compared with $388 million at December 31, 2011. If these leases were included as debt, the Corporation's December 31, 2012 debt to capitalization ratio would increase to 28.5% from 27.7%.

See also Note 17, Guarantees and Contingencies in the notes to the Consolidated Financial Statements.

Foreign Operations

The Corporation conducts exploration and production activities outside the United States, principally in Algeria, Australia, Azerbaijan, Brunei, China, Denmark, Equatorial Guinea, France, Ghana, Indonesia, the Kurdistan region of Iraq, Libya, Malaysia, Norway, Russia, Thailand and the United Kingdom. Therefore, the Corporation is subject to the risks associated with foreign operations, including political risk, acts of terrorism, tax law changes and currency risk.

See also Item 1A. Risk Factors Related to Our Business and Operations.

Accounting Policies

Critical Accounting Policies and Estimates

Accounting policies and estimates affect the recognition of assets and liabilities in the Corporation's 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, the Corporation's 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. The Corporation maintains its own internal reserve estimates that are calculated by technical staff that work directly with the oil and gas properties. The Corporation's 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. The Corporation also engages an independent third party consulting firm to audit approximately 80% of the Corporation's total proved reserves.

Impairment of Long-lived Assets and Goodwill: As explained below, there are significant differences in the way long-lived assets and goodwill are evaluated and measured for impairment testing. The Corporation reviews 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 undiscounted future net cash flow estimates, the assets are impaired and an impairment loss is recorded. The amount of impairment is 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.

The Corporation's impairment tests of long-lived E&P producing assets are based on its 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. The Corporation 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.

The Corporation's goodwill is tested for impairment annually in the fourth quarter or when events or circumstances indicate that the carrying amount of the goodwill may not be recoverable. 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. The Corporation has concluded that the E&P segment is the reporting unit for the purposes of testing goodwill for impairment, since the E&P segment is managed globally by one segment manager who allocates financial and technical resources globally and reviews operating results at the segment level. Accordingly, the Corporation expects that the benefits of goodwill will be recovered through the operations of that segment.

If any of the E&P segment components, such as our financial reporting regions (United States, Europe, Africa and Asia) were considered to be reporting units, an analysis would be performed to determine if these components were economically similar as defined in the accounting standard for goodwill (ASC 350-20-35). If components are economically similar, that guidance requires that those components be aggregated and deemed a single reporting unit.

While the Corporation believes that the E&P segment is the reporting unit because of the manner in which the business is managed, it also evaluated the required aggregation criteria specified in the accounting standard for segment reporting (ASC 280-10-50-11) and determined that its components are economically similar for the following reasons:

- The Corporation operates its exploration and production segment as a single, global business.
- Each component produces oil and gas.
- The exploration and production processes are similar in each component.
- The methods used by each component to market and distribute oil and gas are similar.
- Customers of each component are similar.
- The components share technical resources and support services.

If the Corporation reorganized its exploration and production business such that there was more than one reporting unit, goodwill may be assigned to two or more reporting units.

The Corporation's fair value estimate of the E&P segment is the sum of: (1) the discounted anticipated cash flows of producing assets and known developments, (2) the estimated risk adjusted present value of exploration assets, and (3) 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, improved processes and increased market share. The Corporation also considers the relative market valuation of similar E&P companies.

The determination of the fair value of the E&P segment depends on estimates about oil and gas reserves, future prices, timing of future net cash flows and market premiums. Significant extended declines in crude oil and natural gas prices or reduced reserve estimates could lead to a decrease in the fair value of the E&P segment that could result in an impairment of goodwill.

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 to the E&P segment.

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.

The Corporation has net operating loss carryforwards or credit carryforwards in several jurisdictions, including the United States, and has recorded deferred tax assets for those losses and credits. Additionally, the Corporation has 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 realizability of deferred tax assets, the Corporation refers to the reversal periods for available carryforward periods for net operating losses and credit carryforwards, temporary differences, 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 the Corporation’s internal business forecasts. Additionally, the Corporation has income taxes which have been deferred on intercompany transactions eliminated in consolidation related to transfers of property, plant and equipment remaining within the consolidated group. The amortization of these income taxes deferred on intercompany transactions will occur ratably with the recovery through depletion and depreciation of the carrying value of these assets. The Corporation does 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: The Corporation has 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, the Corporation recognizes a liability for the fair value of required asset retirement obligations. In addition, the fair value of any legally required conditional asset retirement obligations is recorded if the liability can be reasonably estimated. The Corporation capitalizes such costs as a component of the carrying amount of the underlying assets in the period in which the liability is incurred. In order to measure these obligations, the Corporation estimates the fair value of the obligations by discounting the future payments that will be required to satisfy the obligations. In determining these estimates, the Corporation is 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, the Corporation’s 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: The Corporation has funded non-contributory defined benefit pension plans and an unfunded supplemental pension plan. The Corporation recognizes in the Consolidated Balance Sheet the net change in the funded status of the projected benefit obligation for these plans.

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; and rate of future increases in compensation levels. These assumptions represent estimates made by the Corporation, some of which can be affected by external factors. For example, the discount rate used to estimate the Corporation’s 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 the Corporation's financial statements.

Derivatives: The Corporation utilizes derivative instruments for both risk management and trading activities. In risk management activities, the Corporation uses futures, forwards, options and swaps, individually or in combination to mitigate its exposure to fluctuations in the prices of crude oil, natural gas, refined petroleum products and electricity, as well as changes in interest and foreign currency exchange rates. In trading activities, the Corporation, principally through a consolidated partnership, trades energy-related commodities and derivatives, including futures, forwards, options and swaps, based on expectations of future market conditions.

All derivative instruments are recorded at fair value in the Corporation's Consolidated Balance Sheet. The Corporation's 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.

Derivatives that are designated as either cash flow or fair value hedges are tested for effectiveness prospectively before they are executed and both prospectively and retrospectively on an on-going basis to determine whether they continue to qualify for hedge accounting. The prospective and retrospective effectiveness calculations are performed using either historical simulation or other statistical models, which utilize historical observable market data consisting of futures curves and spot prices.

Fair Value Measurements: The Corporation's derivative instruments are recorded at fair value, with changes in fair value recognized in earnings or other comprehensive income each period as appropriate. The Corporation uses various valuation approaches in determining fair value, including the market and income approaches. The Corporation's fair value measurements also include non-performance risk and time value of money considerations. Counterparty credit is considered for receivable balances, and the Corporation's credit is considered for accrued liabilities.

The Corporation also records 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.

The Corporation determines 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). 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. To value derivatives that are characterized as Level 2 and 3, the Corporation uses observable inputs for similar instruments that are available from exchanges, pricing services or broker quotes. These observable inputs may be supplemented with other methods, including internal extrapolation or interpolation, that result in the most representative prices for instruments with similar characteristics. 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. The fair value of certain of the Corporation's exchange traded futures and options are considered Level 1.

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. The Corporation utilizes fair value measurements based on Level 2 inputs for certain forwards, swaps and options.

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. For example, in its energy marketing business, the Corporation sells natural gas and electricity to customers and offsets the price exposure by purchasing forward contracts. The fair value of these sales and purchases may be based on specific prices at less liquid delivered locations, which are classified as Level 3. Fair values determined using discounted cash flows and other unobservable data are also classified as Level 3.

Impairment of Equity Investees: The Corporation reviews equity method investments for impairment whenever events or changes in circumstances indicate that an other than temporary decline in value may have occurred. The fair value measurement used in the impairment assessment is based on quoted market prices, where available, or other valuation techniques, including discounted cash flows.

Environment, Health and Safety

The Corporation's 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 the Corporation's environment, health, safety and social responsibility (EHS & SR) policies and by a management system framework that helps protect the Corporation's workforce, customers and local communities. The Corporation's 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 the Corporation's 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. The Corporation has 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.

Over the last several years, many refineries have entered into consent agreements to resolve the United States Environmental Protection Agency's (EPA) assertions that refining facilities were modified or expanded without complying with the New Source Review regulations that require permits and new emission controls in certain circumstances and other regulations that impose emissions control requirements. In April 2012, the Corporation entered into a consent decree with the EPA to resolve these matters as they relate to its Port Reading refinery facility. Under the terms of the Consent Decree, Hess paid a penalty of $850,000 and agreed to implement a program to reduce emissions at the refinery. The emissions reduction program in the Consent Decree is not expected to have a material adverse impact on the financial condition, results of operations or cash flows of the Corporation. In January 2013, the Corporation announced its decision to cease refining operations in February at its Port Reading facility.

The Corporation recognizes that climate change is a global environmental concern. The Corporation assesses, monitors and takes measures to reduce our carbon footprint at existing and planned operations. The Corporation is committed to complying with all Greenhouse Gas (GHG) emissions mandates and the responsible management of GHG emissions at its facilities.

The Corporation will have continuing expenditures for environmental assessment and remediation. Sites where corrective action may be necessary include gasoline stations, terminals, onshore exploration and production facilities, refineries (including solid waste management units under permits issued pursuant to the Resource Conservation and Recovery Act) and, although not currently significant, "Superfund" sites where the Corporation has been named a potentially responsible party.

The Corporation accrues for environmental assessment and remediation expenses when the future costs are probable and reasonably estimable. At year-end 2012, the Corporation's reserve for estimated remediation liabilities was approximately $55 million. The Corporation expects that existing reserves for environmental liabilities will adequately cover costs to assess and remediate known sites. The Corporation's remediation spending was $19 million in 2012, $19 million in 2011 and $13 million in 2010. Capital expenditures for facilities, primarily to comply with federal, state and local environmental standards, other than for the low sulfur requirements, were approximately $70 million in 2012, $95 million in 2011 and $85 million in 2010.

Forward-looking Information

Certain sections of this Annual Report on Form 10-K, including Business and Properties, Management's Discussion and Analysis of Financial Condition and Results of Operations and Quantitative and Qualitative Disclosures about Market Risk, include references to the Corporation's future results of operations and financial position, liquidity and capital resources, capital expenditures, asset sales, oil and gas production, tax rates, debt repayment, hedging, derivative, market risk and environmental disclosures, off-balance sheet arrangements and contractual obligations and contingencies, which include forward-looking information. These sections typically include statements with words such as "anticipate", "estimate", "expect", "forecast", "guidance", "could", "may", "should", "would" or similar words, indicating that future outcomes are uncertain. Forward-looking disclosures are based on the Corporation's current understanding and assessment of these activities and reasonable assumptions about the future. Actual results may differ from these disclosures because of changes in market conditions, government actions and other factors. For more information regarding the factors that may cause the Corporation's results to differ from these statements, see Item 1A. Risk Factors Related to Our Business and Operations.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

In the normal course of its business, the Corporation is exposed to commodity risks related to changes in the prices of crude oil, natural gas, refined petroleum products and electricity, as well as to changes in interest rates and foreign currency values. In the disclosures that follow, risk management activities are referred to as energy marketing and corporate risk management activities. The Corporation also has trading operations, principally through a 50% voting interest in a consolidated partnership, that trades energy-related commodities, securities and derivatives. These activities are also exposed to commodity risks primarily related to the prices of crude oil, natural gas, refined petroleum products and electricity. The following describes how these risks are controlled and managed.

Controls: The Corporation maintains a control environment under the direction of its chief risk officer and through its corporate risk policy, which the Corporation's senior management has approved. Controls include volumetric, term and value at risk limits. The chief risk officer must approve the trading of new instruments or commodities. Risk limits are monitored and are reported on a daily basis to business units and senior management. The Corporation's risk management department also performs independent price verifications (IPV's) of sources of fair values, validations of valuation models and analyzes changes in fair value measurements on a daily, monthly and/or quarterly basis. These controls apply to all of the Corporation's risk management and trading activities, including the consolidated trading partnership. The Corporation's treasury department is responsible for administering and monitoring foreign exchange rate and interest rate hedging programs using similar controls and processes, where applicable.

The Corporation uses value at risk to monitor and control commodity risk within its risk management and trading activities. The value at risk model uses historical simulation and the results represent the potential loss in fair value over one day at a 95% confidence level. The model captures both first and second order sensitivities for options. Results may vary from time to time as strategies change in trading activities or hedging levels change in risk management activities.

Instruments: The Corporation primarily uses forward commodity contracts, foreign exchange forward contracts, futures, swaps, options and energy commodity based securities in its risk management and trading activities. These contracts are generally widely traded instruments with standardized terms. The following describes these instruments and how the Corporation uses them:

- *Forward Commodity Contracts:* The Corporation enters into contracts for the forward purchase and sale of commodities. At settlement date, the notional value of the contract is exchanged for physical delivery of the commodity. Forward contracts that are deemed normal purchase and sale contracts are excluded from the quantitative market risk disclosures.

Table of Contents

- *Forward Foreign Exchange Contracts:* The Corporation enters into forward contracts primarily for the British Pound and the Thai Baht, which commit the Corporation to buy or sell a fixed amount of these currencies at a predetermined exchange rate on a future date.
- *Exchange Traded Contracts:* The Corporation uses 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.
- *Swaps:* The Corporation uses financially settled swap contracts with third parties as part of its risk management and trading 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.
- *Options:* Options on various underlying energy commodities include exchange traded and third party contracts and have various exercise periods. As a seller of options, the Corporation receives a premium at the outset and bears the risk of unfavorable changes in the price of the commodity underlying the option. As a purchaser of options, the Corporation pays a premium at the outset and has the right to participate in the favorable price movements in the underlying commodities.
- *Energy Securities:* Energy securities include energy-related equity or debt securities issued by a company or government or related derivatives on these securities.

Risk Management Activities

Energy marketing activities: In its energy marketing activities, the Corporation sells refined petroleum products, natural gas and electricity principally to commercial and industrial businesses at fixed and floating prices for varying periods of time. Commodity contracts such as futures, forwards, swaps and options together with physical assets, such as storage, are used to obtain supply and reduce margin volatility or lower costs related to sales contracts with customers.

Corporate risk management: Corporate risk management activities include transactions designed to reduce risk in the selling prices of crude oil, refined petroleum products or natural gas produced by the Corporation 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 the Corporation's crude oil or natural gas production. Forward contracts may also be used to purchase certain currencies in which the Corporation does 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.

The Corporation has outstanding foreign exchange contracts used to reduce its exposure to fluctuating foreign exchange rates for various currencies, including the British Pound and the Thai Baht. At December 31, 2012, the Corporation had a receivable for foreign exchange contracts maturing in 2013 with a fair value of $14 million. The change in fair value of the foreign exchange contracts from a 10% strengthening of the U.S. Dollar exchange rate is estimated to be a loss of approximately $125 million at December 31, 2012.

The Corporation's outstanding long-term debt of $7,361 million, including current maturities, has a fair value of $8,887 million at December 31, 2012. A 15% decrease in the rate of interest would increase the fair value of debt by approximately $200 million at December 31, 2012.

Following is the value at risk for the Corporation's energy marketing and risk management commodity derivatives activities, excluding foreign exchange and interest rate derivatives described above:

	2012	2011
	(In millions)	
At December 31	**$ 7**	$ 94
Average	**49**	30
High	**95**	94
Low	**7**	8

The decrease in the value at risk for the Corporation's energy marketing and risk management commodity derivatives activities in 2012 primarily reflects the maturing of Brent crude oil cash flow hedge positions as described in Note 20, Risk Management and Trading Activities in the notes to the Consolidated Financial Statements.

Trading Activities

Trading activities are conducted principally through a trading partnership in which the Corporation has a 50% voting interest. This consolidated entity intends to generate earnings through various strategies primarily using energy commodities, securities and derivatives. The Corporation also takes trading positions for its own account.

Following is the value at risk for the Corporation's trading activities:

	2012	2011
	(In millions)	
At December 31	**$ 4**	$ 4
Average	**6**	11
High	**7**	16
Low	**4**	4

The information that follows represents 100% of the trading partnership and the Corporation's proprietary trading accounts. Derivative trading transactions are marked-to-market and unrealized gains or losses are recognized currently in earnings. Gains or losses from sales of physical products are recorded at the time of sale. Net realized gains on trading activities amounted to $60 million in 2012 and $44 million in 2011. The following table provides an assessment of the factors affecting the changes in fair value of financial instruments and derivative commodity contracts used in trading activities:

	2012	2011
	(In millions)	
Fair value of contracts outstanding at January 1	**$ (86)**	$ 94
Change in fair value of contracts outstanding at the beginning of the year and still outstanding at the end of the year	**17**	(69)
Reversal of fair value for contracts closed during the year	**70**	9
Fair value of contracts entered into during the year and still outstanding	**(97)**	(120)
Fair value of contracts outstanding at December 31	**$ (96)**	$ (86)

The following table summarizes the sources of net asset (liability) fair values of financial instruments and derivative commodity contracts by year of maturity used in the Corporation's trading activities at December 31, 2012:

	Total	2013	2014	2015	2016 and Beyond
			(In millions)		
Sources of fair value					
Level 1	$ 8	$ 38	$ 4	$ (21)	$ (13)
Level 2	(141)	(80)	(30)	(33)	2
Level 3	37	10	—	30	(3)
Total	$ (96)	$ (32)	$ (26)	$ (24)	$ (14)

The following table summarizes the receivables net of cash margin and letters of credit relating to the Corporation's trading activities and the credit ratings of counterparties at December 31:

	2012	2011
	(In millions)	
Investment grade determined by outside sources	**$ 294**	$ 389
Investment grade determined internally*	**59**	304
Less than investment grade	**39**	89
Fair value of net receivables outstanding at December 31	**$ 392**	$ 782

** Based on information provided by counterparties and other available sources.*

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. Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2012.

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, 2012, as stated in their report, which is included herein.

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

By /s/ John B. Hess
John B. Hess
Chairman of the Board and
Chief Executive Officer

February 28, 2013

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, 2012, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (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, 2012 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, 2012 and 2011, 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, 2012 of Hess Corporation and consolidated subsidiaries, and our report dated February 28, 2013 expressed an unqualified opinion thereon.

/S/ ERNST & YOUNG, LLP
February 28, 2013
New York, New York

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Hess Corporation

We have audited the accompanying consolidated balance sheet of Hess Corporation and consolidated subsidiaries (the "Corporation") as of December 31, 2012 and 2011, 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, 2012. 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, 2012 and 2011, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2013 expressed an unqualified opinion thereon.

/S/ ERNST & YOUNG, LLP
February 28, 2013
New York, New York

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	December 31, 2012	December 31, 2011
	(In millions, except share amounts)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 642**	$ 351
Accounts receivable		
Trade	**4,057**	4,761
Other	**281**	250
Inventories	**1,259**	1,423
Other current assets	**2,148**	1,554
Total current assets	**8,387**	8,339
INVESTMENTS IN AFFILIATES	**443**	384
PROPERTY, PLANT AND EQUIPMENT		
Total — at cost	**45,553**	39,710
Less: Reserves for depreciation, depletion, amortization and lease impairment	**16,746**	14,998
Property, plant and equipment — net	**28,807**	24,712
GOODWILL	**2,208**	2,305
DEFERRED INCOME TAXES	**3,126**	2,941
OTHER ASSETS	**470**	455
TOTAL ASSETS	**$ 43,441**	$ 39,136
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	**$ 2,809**	$ 3,712
Accrued liabilities	**3,826**	3,524
Taxes payable	**960**	812
Short-term debt and current maturities of long-term debt	**787**	52
Total current liabilities	**8,382**	8,100
LONG-TERM DEBT	**7,324**	6,005
DEFERRED INCOME TAXES	**2,662**	2,843
ASSET RETIREMENT OBLIGATIONS	**2,212**	1,844
OTHER LIABILITIES AND DEFERRED CREDITS	**1,658**	1,752
Total liabilities	**22,238**	20,544
EQUITY		
Hess Corporation Stockholders' Equity		
Common stock, par value $1.00		
Authorized — 600,000,000 shares		
Issued: 2012 — 341,527,617 shares; 2011 — 339,975,610 shares	**342**	340
Capital in excess of par value	**3,524**	3,417
Retained earnings	**17,717**	15,826
Accumulated other comprehensive income (loss)	**(493)**	(1,067)
Total Hess Corporation stockholders' equity	**21,090**	18,516
Noncontrolling interests	**113**	76
Total equity	**21,203**	18,592
TOTAL LIABILITIES AND EQUITY	**$ 43,441**	$ 39,136

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

See accompanying notes to consolidated financial statements.

Table of Contents

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED INCOME

	Years Ended December 31,		
	2012	2011	2010
	(In millions, except per share amounts)		
REVENUES AND NON-OPERATING INCOME			
Sales (excluding excise taxes) and other operating revenues	**$ 37,691**	$ 38,466	$ 33,862
Loss from equity investment in HOVENSA L.L.C.	—	(1,073)	(522)
Gains on asset sales	**584**	446	1,208
Other, net	**98**	32	65
Total revenues and non-operating income	**38,373**	37,871	34,613
COSTS AND EXPENSES			
Cost of products sold (excluding items shown separately below)	**24,917**	26,774	23,407
Production expenses	**2,752**	2,352	1,924
Marketing expenses	**1,057**	1,069	1,021
Exploration expenses, including dry holes and lease impairment	**1,070**	1,195	865
Other operating expenses	**166**	171	213
General and administrative expenses	**707**	702	662
Interest expense	**419**	383	361
Depreciation, depletion and amortization	**2,949**	2,406	2,317
Asset impairments	**598**	358	532
Total costs and expenses	**34,635**	35,410	31,302
INCOME BEFORE INCOME TAXES	**3,738**	2,461	3,311
Provision for income taxes	**1,675**	785	1,173
NET INCOME	**$ 2,063**	$ 1,676	$ 2,138
Less: Net income (loss) attributable to noncontrolling interests	**38**	(27)	13
NET INCOME ATTRIBUTABLE TO HESS CORPORATION	**$ 2,025**	$ 1,703	$ 2,125
BASIC NET INCOME PER SHARE	**$ 5.98**	$ 5.05	$ 6.52
DILUTED NET INCOME PER SHARE	**$ 5.95**	$ 5.01	$ 6.47
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING (DILUTED)	**340.3**	339.9	328.3

See accompanying notes to consolidated financial statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME

	Years Ended December 31,		
	2012	2011	2010
		(In millions)	
NET INCOME	**$ 2,063**	$ 1,676	$ 2,138
OTHER COMPREHENSIVE INCOME (LOSS):			
Derivatives designated as cash flow hedges			
Effect of hedge losses reclassified to income	**676**	690	1,060
Income taxes on effect of hedge losses reclassified to income	**(252)**	(258)	(404)
Net effect of hedge losses reclassified to income	**424**	432	656
Change in fair value of cash flow hedges	**(156)**	4	(326)
Income taxes on change in fair value of cash flow hedges	**60**	(2)	128
Net change in fair value of cash flow hedges	**(96)**	2	(198)
Change in cash flow hedges, after-tax	**328**	434	458
Pension and other postretirement plans			
Change in plan liabilities	**(15)**	(391)	27
Income taxes on change in plan liabilities	**7**	145	1
Change in plan liabilities, after-tax	**(8)**	(246)	28
Foreign currency translation adjustment and other	**256**	(94)	31
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	**576**	94	517
COMPREHENSIVE INCOME	**2,639**	1,770	2,655
Less: Comprehensive income (loss) attributable to noncontrolling interests	**40**	(25)	14
COMPREHENSIVE INCOME ATTRIBUTABLE TO HESS CORPORATION	**$ 2,599**	$ 1,795	$ 2,641

See accompanying notes to consolidated financial statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED CASH FLOWS

	Years Ended December 31,		
	2012	2011	2010
		(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 2,063**	$ 1,676	$ 2,138
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	**2,949**	2,406	2,317
Loss from equity investment in HOVENSA L.L.C.	**—**	1,073	522
Asset impairments	**598**	358	532
Exploratory dry hole costs	**377**	438	237
Lease impairment	**223**	301	266
Stock compensation expense	**99**	104	112
Gains on asset sales	**(584)**	(446)	(1,208)
Provision (benefit) for deferred income taxes	**(459)**	(623)	(495)
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	**634**	(243)	(760)
(Increase) decrease in inventories	**168**	4	(16)
Increase (decrease) in accounts payable and accrued liabilities	**(30)**	544	1,141
Increase (decrease) in taxes payable	**28**	46	95
Changes in other assets and liabilities	**(406)**	(654)	(351)
Net cash provided by operating activities	**5,660**	4,984	4,530
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	**(7,795)**	(7,006)	(5,492)
Proceeds from asset sales	**843**	490	183
Other, net	**(99)**	(50)	50
Net cash used in investing activities	**(7,051)**	(6,566)	(5,259)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings of debt with maturities of 90 days or less	**1,648**	100	—
Debt with maturities of greater than 90 days			
Borrowings	**630**	422	1,278
Repayments	**(433)**	(100)	(180)
Cash dividends paid	**(171)**	(136)	(131)
Noncontrolling interests, net	**(3)**	(49)	(46)
Employee stock options exercised, including income tax benefits	**11**	88	54
Net cash provided by financing activities	**1,682**	325	975
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**291**	(1,257)	246
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**351**	1,608	1,362
CASH AND CASH EQUIVALENTS AT END OF YEAR	**$ 642**	$ 351	$ 1,608

See accompanying notes to consolidated financial statements.

Table of Contents

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, 2010	$ 327	$ 2,481	$ 12,251	$ (1,675)	$ 13,384	$ 144	$ 13,528
Net income			2,125		2,125	13	2,138
Other comprehensive income (loss)				516	516	1	517
Comprehensive income (loss)					2,641	14	2,655
Common stock issued for acquisition	9	639	—	—	648	—	648
Activity related to restricted common stock awards, net	1	59	—	—	60	—	60
Employee stock options, including income tax benefits	1	105	—	—	106	—	106
Cash dividends declared	—	—	(132)	—	(132)	—	(132)
Noncontrolling interests, net	—	(28)	10	—	(18)	(38)	(56)
Balance at December 31, 2010	338	3,256	14,254	(1,159)	16,689	120	16,809
Net income			1,703		1,703	(27)	1,676
Other comprehensive income (loss)				92	92	2	94
Comprehensive income (loss)					1,795	(25)	1,770
Activity related to restricted common stock awards, net	1	52	—	—	53	—	53
Employee stock options, including income tax benefits	1	138	—	—	139	—	139
Cash dividends declared	—	—	(136)	—	(136)	—	(136)
Noncontrolling interests, net	—	(29)	5	—	(24)	(19)	(43)
Balance at December 31, 2011	340	3,417	15,826	(1,067)	18,516	76	18,592
Net income			**2,025**		**2,025**	**38**	**2,063**
Other comprehensive income (loss)				**574**	**574**	**2**	**576**
Comprehensive income (loss)					**2,599**	**40**	**2,639**
Activity related to restricted common stock awards, net	**2**	**55**	**—**	**—**	**57**	**—**	**57**
Employee stock options, including income tax benefits	**—**	**44**	**—**	**—**	**44**	**—**	**44**
Performance share units	**—**	**8**	**—**	**—**	**8**	**—**	**8**
Cash dividends declared	**—**	**—**	**(136)**	**—**	**(136)**	**—**	**(136)**
Noncontrolling interests, net	**—**	**—**	**2**	**—**	**2**	**(3)**	**(1)**
Balance at December 31, 2012	**$ 342**	**$ 3,524**	**$ 17,717**	**$ (493)**	**$ 21,090**	**$ 113**	**$ 21,203**

See accompanying notes to consolidated financial statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Nature of Business: Hess Corporation and its subsidiaries (the Corporation or Hess) operate in two segments, Exploration and Production (E&P) and Marketing and Refining (M&R). The E&P segment explores for, develops, produces, purchases, transports and sells crude oil and natural gas. The M&R segment purchases, markets and trades refined petroleum products, natural gas and electricity. The Corporation also operates terminals and retail gasoline stations, most of which include convenience stores, that are located on the East Coast of the United States. Through February 2013, the Corporation also manufactured refined petroleum products. In January 2013, the Corporation announced its decision to cease refining operations at its Port Reading facility in February and pursue the sale of its terminal network. In January 2012, HOVENSA L.L.C. (HOVENSA), a 50% owned joint venture in the U.S. Virgin Islands, shut down its refinery. HOVENSA plans to operate the complex as an oil storage terminal while the Corporation and its joint venture partner pursue a sale of HOVENSA.

The Corporation has made significant progress in its transformation from an integrated oil and gas company to a predominantly E&P company following the shutdown of the HOVENSA joint venture refinery and its decision to cease refining operations at its Port Reading facility and pursue the sale of its terminal network. The Corporation has also shifted its E&P growth strategy from one based primarily on high impact exploration to one based on a combination of the development of unconventional resources, exploitation of existing discoveries and a smaller, more focused exploratory program.

Principles of Consolidation and Basis of Presentation: The consolidated financial statements include the accounts of Hess Corporation and entities in which the Corporation owns more than a 50% voting interest or entities that the Corporation controls. The Corporation consolidates the trading partnership in which it owns a 50% voting interest and over which it exercises control. The Corporation's undivided interests in unincorporated oil and gas exploration and production ventures are proportionately consolidated. Investments in affiliated companies, 20% to 50% owned and where the Corporation has the ability to influence the operating or financial decisions of the affiliate, are accounted for using the equity method.

Certain information in the financial statements and notes has been reclassified to conform to the current period presentation. In the preparation of these financial statements, the Corporation has evaluated subsequent events through the date of issuance.

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. Among the estimates made by management are oil and gas reserves, asset valuations, depreciable lives, pension liabilities, legal and environmental obligations, asset retirement obligations and income taxes.

Revenue Recognition: The Corporation recognizes revenues from the sale of crude oil, natural gas, refined petroleum products and other merchandise when title passes to the customer. Sales are reported net of excise and similar taxes in the Statement of Consolidated Income. The Corporation recognizes revenues from the production of natural gas properties based on sales to customers. Differences between E&P natural gas volumes sold and the Corporation's share of natural gas production are not material. Revenues from natural gas and electricity sales by the Corporation's marketing operations are recognized based on meter readings and estimated deliveries to customers since the last meter reading.

In its E&P activities, the Corporation engages 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. Similarly, in its marketing activities, the Corporation enters into refined petroleum product purchase and sale transactions with the same counterparty. These arrangements are reported net in Sales and other operating revenues in the Statement of Consolidated Income.

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.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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: The Corporation records 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 equipment 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. Retail gas stations and equipment related to a leased property, are depreciated over the estimated useful lives not to exceed the remaining lease period. The Corporation records the cost of acquired customers in its energy marketing activities as intangible assets and amortizes these costs on the straight-line method over the expected renewal period based on historical experience.

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: The Corporation reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted future cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is 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 net present value of future 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 the average prices used in the standardized measure of discounted future net cash flows.

Impairment of Equity Investees: The Corporation reviews equity method investments for impairment whenever events or changes in circumstances indicate that an other than temporary decline in value may have occurred. The fair value measurement used in the impairment assessment is based on quoted market prices, where available, or other valuation techniques, including discounted cash flows.

Impairment of Goodwill: Goodwill is tested for impairment annually in the fourth quarter or when events or changes in circumstances indicate that the carrying amount of the goodwill may not be recoverable. This impairment test is calculated at the reporting unit level, which for the Corporation's goodwill is the E&P operating segment. The Corporation identifies potential impairments by comparing the fair value of the reporting unit to its book value, including goodwill. If the fair value of the reporting unit exceeds the carrying amount, goodwill is not impaired. If the carrying value exceeds the fair value, the Corporation calculates the possible impairment loss by comparing the implied fair value of goodwill with the carrying amount. If the implied fair value of goodwill is less than the carrying amount, an impairment would be recorded.

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. For refined petroleum product inventories valued at cost, the Corporation uses principally the last-in, first-out (LIFO) inventory method. For the remaining inventories, cost is generally determined using average actual costs.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Income Taxes: Deferred income taxes are determined using the liability method. The Corporation regularly assesses the realizability of deferred tax assets, based on estimates of future taxable income, the availability of tax planning strategies, the existence of appreciated assets, the available carryforward periods for net operating losses and other factors. 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 expected to be realized. In addition, the Corporation recognizes 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. Additionally, the Corporation has income taxes which have been deferred on intercompany transactions eliminated in consolidation related to transfers of property, plant and equipment remaining within the consolidated group. The amortization of these income taxes deferred on intercompany transactions will occur ratably with the recovery through depletion and depreciation of the carrying value of these assets. The Corporation does not provide for deferred U.S. income taxes for that portion of undistributed earnings of foreign subsidiaries that are indefinitely reinvested in foreign operations. The Corporation classifies interest and penalties associated with uncertain tax positions as income tax expense.

Asset Retirement Obligations: The Corporation has material legal obligations to remove and dismantle long-lived assets and to restore land or seabed at certain exploration and production locations. The Corporation recognizes a liability for the fair value of legally required asset retirement obligations associated with long-lived assets in the period in which the retirement obligations are incurred. In addition, the fair value of any legally required conditional asset retirement obligations is recorded if the liability can be reasonably estimated. The Corporation capitalizes the associated asset retirement costs as part of the carrying amount of the long-lived assets.

Retirement Plans: The Corporation recognizes 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. The Corporation recognizes 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: The Corporation utilizes derivative instruments for both risk management and trading activities. In risk management activities, the Corporation uses futures, forwards, options and swaps, individually or in combination, to mitigate its exposure to fluctuations in prices of crude oil, natural gas, refined petroleum products and electricity, as well as changes in interest and foreign currency exchange rates. In trading activities, the Corporation, principally through a consolidated partnership, trades energy-related commodities and derivatives, including futures, forwards, options and swaps based on expectations of future market conditions.

All derivative instruments are recorded at fair value in the Corporation's Consolidated Balance Sheet. The Corporation's 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: The Corporation's derivative instruments are recorded at fair value, with changes in fair value recognized in earnings or other comprehensive income each period as appropriate. The Corporation uses various valuation approaches in determining fair value, including the market and income approaches. The Corporation's fair value measurements also include non-performance risk and time value of money considerations. Counterparty credit is considered for receivable balances, and the Corporation's credit is considered for accrued liabilities.

The Corporation also records 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.

The Corporation determines 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). 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. To value derivatives that are characterized as Level 2 and 3, the Corporation uses observable inputs for similar instruments that are available from exchanges, pricing services or broker quotes. These observable inputs may be supplemented with other methods, including internal extrapolation or interpolation, that result in the most representative prices for instruments with similar characteristics. 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. The fair value of certain of the Corporation's exchange traded futures and options are considered Level 1.

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. The Corporation utilizes fair value measurements based on Level 2 inputs for certain forwards, swaps and options.

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. For example, in its energy marketing business, the Corporation enters into contracts to sell natural gas and electricity to customers and offsets the price exposure by purchasing forward contracts. The fair value of these sales and purchases may be based on specific prices at less liquid delivered locations, which are classified as Level 3. There may be offsets to these positions that are priced based on more liquid markets, which are, therefore, classified as Level 1 or Level 2. Fair values determined using discounted cash flows and other unobservable data are also classified as Level 3.

Share-based Compensation: 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.

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 translating monetary assets and liabilities that are denominated in a non-functional currency into 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, adjustments resulting from translating foreign currency assets and liabilities into U.S. Dollars are recorded in a separate component of equity titled Accumulated other comprehensive income (loss).

Maintenance and Repairs: Maintenance and repairs are expensed as incurred, including costs of refinery turnarounds. Capital improvements are recorded as additions in Property, plant and equipment.

Environmental Expenditures: The Corporation accrues and expenses environmental costs to remediate existing conditions related to past operations when the future costs are probable and reasonably estimable. The Corporation capitalizes environmental expenditures that increase the life or efficiency of property or reduce or prevent future adverse impacts to the environment.

Changes in Accounting Policies: Effective January 1, 2012, the Corporation adopted the provisions of Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income, which requires comprehensive income to be presented either at the end of the income statement or as a separate statement immediately following the income statement. The Corporation elected to adopt the separate statement method.

Effective January 1, 2012, the Corporation adopted FASB ASU 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. For the Corporation, this standard requires additional disclosures related to fair value measurements, which are included in Note 20, Risk Management and Trading Activities.

2. Dispositions

2012: In October 2012, the Corporation completed the sale of its interests in the Bittern Field (Hess 28%) in the United Kingdom North Sea and the associated Triton floating production, storage and offloading vessel for cash proceeds of $187 million. The transaction resulted in an after-tax gain of $172 million, after deducting the net book value of assets including allocated goodwill of $12 million.

In September 2012, the Corporation completed the sale of its interests in the Schiehallion Field (Hess 16%) in the United Kingdom North Sea, its share of the associated floating production, storage and offloading vessel, and the West of Shetland pipeline system for cash proceeds of $524 million. The transaction resulted in a pre-tax gain of $376 million ($349 million after income taxes), after deducting the net book value of assets including allocated goodwill of $27 million.

In January 2012, the Corporation completed the sale of its interest in the Snohvit Field (Snohvit) (Hess 3%), a liquefied natural gas project, offshore Norway, for cash proceeds of $132 million. The transaction resulted in an after-tax gain of $36 million, after deducting the net book value of assets including allocated goodwill of $14 million.

See also Note 6, Property, Plant and Equipment in the notes to the Consolidated Financial Statements for a description of the assets held for sale at December 31, 2012.

2011: In February 2011, the Corporation completed the sale of its interests in certain natural gas producing assets in the United Kingdom North Sea for cash proceeds of $359 million. These disposals resulted in pre-tax gains totaling $343 million ($310 million after income taxes). The total combined net book value of the assets prior to the sale was $16 million, including allocated goodwill of $14 million.

In August 2011, the Corporation completed the sale of its interests in the Snorre Field (Hess 1%), offshore Norway and the Cook Field (Hess 28%) in the United Kingdom North Sea for cash proceeds of $131 million. These disposals resulted in after-tax gains totaling $103 million. The total combined net book value of the disposed assets prior to the sale was $28 million, including allocated goodwill of $11 million.

2010: In January 2010, the Corporation completed the sale of its interest in the Jambi Merang natural gas development project in Indonesia (Hess 25%) for cash proceeds of $183 million. The transaction resulted in an after-tax gain of $58 million, after deducting the net book value of assets including goodwill of $7 million.

3. Acquisitions

2011: In the third quarter of 2011, the Corporation entered into agreements to acquire approximately 85,000 net acres in the Utica Shale play in Ohio for approximately $750 million, principally through the acquisition of Marquette Exploration, LLC (Marquette). This acquisition strengthened the Corporation's portfolio of unconventional assets. The acquisition of Marquette was accounted for as a business combination and the assets acquired and the liabilities assumed were recorded at fair value. The fair value measurements of the oil and gas assets were based, in part, on significant inputs not observable in the market and thus represent a Level 3 measurement. The majority of the purchase price was assigned to unproved properties and the remainder to producing wells and working capital.

In October 2011, the Corporation completed the acquisition of a 50% undivided interest in CONSOL Energy Inc.'s (CONSOL) approximately 200,000 acres, in the Utica Shale play in Ohio, for $59 million in cash at closing and the agreement to fund 50% of CONSOL's share of the drilling costs up to $534 million within a 5-year period. This transaction was accounted for as an asset acquisition. On January 31, 2013, CONSOL announced that there are chain of title issues with respect to approximately 36,000 acres, most of which likely cannot be cured, and that the value of the Corporation's carry obligation associated with these acres will reduce by approximately $146 million. The reduction in carry and the validation of title on other acreage is being separately analyzed by the Corporation and will not be finally determined until the title verification process is completed.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

2010: In December, the Corporation acquired approximately 167,000 net acres in the Bakken oil shale play (Bakken) in North Dakota from TRZ Energy, LLC for $1,075 million in cash. In December, the Corporation also completed the acquisition of American Oil & Gas Inc. (American Oil & Gas) for approximately $675 million through the issuance of approximately 8.6 million shares of the Corporation's common stock, which increased the Corporation's acreage position in the Bakken by approximately 85,000 net acres. The properties acquired were located near the Corporation's existing acreage. These acquisitions strengthened the Corporation's acreage position in the Bakken, leveraged existing capabilities and infrastructure and are expected to contribute to future reserve and production growth. Both of these transactions were accounted for as business combinations and the majority of the fair value of the assets acquired was assigned to unproved properties. The total goodwill recorded on these transactions was $332 million after final post-closing adjustments.

In September, the Corporation completed the exchange of its interests in Gabon and the Clair Field in the United Kingdom for additional interests of 28% and 25%, respectively, in the Valhall and Hod fields offshore Norway. This non-monetary exchange was accounted for as a business combination. The transaction resulted in a pre-tax gain of $1,150 million ($1,072 million after income taxes). The total combined carrying amount of the disposed assets prior to the exchange was $702 million, including goodwill of $65 million. The Corporation also acquired, from a different third party, additional interests of 8% and 13% in the Valhall and Hod fields, respectively, for $507 million in cash. This acquisition was accounted for as a business combination. As a result of both of these transactions, the Corporation's total interests in the Valhall and Hod fields are 64% and 63%, respectively. The primary reason for these transactions was to acquire long-lived crude oil reserves and future production growth.

For all the 2010 acquisitions and the exchange described above, the assets acquired and liabilities assumed were recorded at fair value. The estimated fair value for property, plant and equipment acquired in these transactions was based primarily on an income approach (Level 3 fair value measurement).

4. Inventories

Inventories at December 31 were as follows:

	2012	2011
	(In millions)	
Crude oil and other charge stocks	**$ 493**	$ 451
Refined petroleum products and natural gas	**1,362**	1,762
Less: LIFO adjustment	**(1,123)**	(1,276)
	732	937
Merchandise, materials and supplies	**527**	486
Total inventories	**$ 1,259**	$ 1,423

The percentage of LIFO inventory to total crude oil, refined petroleum products and natural gas inventories was 71% and 72% at December 31, 2012 and 2011, respectively. During 2012 the Corporation reduced LIFO inventories, which are carried at lower costs than current inventory costs. The effect of the LIFO inventory liquidations was to decrease Cost of products sold by approximately $165 million in 2012 ($104 million after income taxes).

5. HOVENSA L.L.C. Joint Venture

The Corporation has a 50% interest in HOVENSA, a joint venture with a subsidiary of Petroleos de Venezuela, S.A. (PDVSA), which owns a refinery in St. Croix, U.S. Virgin Islands. In January 2012, HOVENSA shut down its refinery as a result of continued substantial operating losses due to global economic conditions and competitive disadvantages versus other refiners, despite efforts to improve operating performance by reducing refining capacity to 350,000 from 500,000 barrels per day in the first half of 2011. During 2012 and continuing into 2013, HOVENSA and the Government of the Virgin Islands engaged in discussions pertaining to HOVENSA's plan to run the facility as an oil storage terminal while the Corporation and its joint venture partner pursue a sale of HOVENSA.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

As a result of continued substantial operating losses and unsuccessful efforts to improve operating performance by reducing refining capacity, HOVENSA prepared an impairment analysis as of December 31, 2011, which concluded that undiscounted future cash flows would not recover the carrying value of its long-lived assets, and recorded an impairment charge and other charges related to the decision to shut down the refinery. For 2011, the Corporation recorded a total of $1,073 million of losses from its equity investment in HOVENSA. These pre-tax losses included $875 million ($525 million after income taxes) due to the impairment recorded by HOVENSA and other charges associated with its decision to shut down the refinery. The Corporation's share of the impairment related losses recorded by HOVENSA represented an amount equivalent to the Corporation's financial support to HOVENSA at December 31, 2011, its planned future funding commitments for costs related to the refinery shutdown, and a charge of $135 million for the write-off of related assets held by the subsidiary which owns the Corporation's investment in HOVENSA. A deferred income tax benefit of $350 million, consisting primarily of U.S. income taxes, was recorded on the Corporation's share of HOVENSA's impairment and refinery shutdown related charges. At December 31, 2011, the Corporation had a liability of $487 million for its planned funding commitments, which was fully funded in 2012.

In December 2010, the Corporation recorded an impairment charge of $300 million before income taxes ($289 million after income taxes) to reduce the carrying value of its equity investment in HOVENSA to its fair value. The investment had been adversely affected by consecutive annual operating losses and a fourth quarter 2010 debt rating downgrade. The Corporation performed an impairment analysis and concluded that its investment had experienced an other than temporary decline in value. The fair value was determined based on an income approach using estimated refined petroleum product selling prices and volumes, related costs of product sold, capital and operating expenditures and a market based discount rate (a Level 3 fair value measurement).

The Corporation's investment in HOVENSA is accounted for using the equity method. In accordance with Rule 3-09 of Regulation S-X, the Corporation has filed financial statements for HOVENSA in this report on Form 10-K.

6. Property, Plant and Equipment

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

	2012	2011
	(In millions)	
Exploration and Production		
Unproved properties	**$ 3,558**	$ 4,064
Proved properties	**4,072**	3,975
Wells, equipment and related facilities	**35,385**	29,239
	43,015	37,278
Marketing, Refining and Corporate	**2,538**	2,432
Total — at cost	**45,553**	39,710
Less: Reserves for depreciation, depletion, amortization and lease impairment	**16,746**	14,998
Property, plant and equipment — net	**$28,807**	$ 24,712

Assets Held for Sale: In September 2012, the Corporation reached an agreement to sell its assets in Azerbaijan consisting of its interests in the Azeri-Chirag-Guneshli (ACG) fields and the associated Baku-Tbilisi-Ceyhan (BTC) pipeline for approximately $1 billion before normal post-closing adjustments. This transaction is subject to various government and regulatory approvals. In October 2012, the Corporation also announced that it had reached an agreement to sell its interests in the Beryl fields in the United Kingdom North Sea. The sale was completed in January 2013 for cash proceeds of approximately $440 million, see Note 21, Subsequent Events in the notes to the Consolidated Financial Statements. At December 31, 2012, long-term assets totaling $1,092 million, primarily comprising the net property, plant and equipment balances and allocated goodwill of $100 million have been classified as held for sale and reported in Other current assets. In addition, related asset retirement obligations and deferred income taxes totaling $539 million were reported in Accrued liabilities. At December 31, 2011, long-term assets totaling $764 million, including goodwill of $62 million and liabilities totaling $556 million were reported as held for sale. Properties classified as held for sale are not depreciated but are subject to impairment testing.

Table of Contents

Capitalized Exploratory Wells 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:

	2012	2011	2010
		(In millions)	
Beginning balance at January 1	**$2,022**	$1,783	$1,437
Additions to capitalized exploratory well costs pending the determination of proved reserves	**407**	512	675
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(41)**	(171)	(87)
Capitalized exploratory well costs charged to expense	**(129)**	(90)	(110)
Dispositions	**—**	(12)	(132)
Ending balance at December 31	**$2,259**	$2,022	$1,783
Number of wells at end of year	**68**	59	77

The preceding table excludes exploratory dry hole costs of $248 million, $348 million and $127 million in 2012, 2011 and 2010, respectively, which were incurred and subsequently expensed in the same year. In 2012, capitalized well costs reclassified based on the determination of proved reserves primarily related to projects in Indonesia, Russia and the Joint Development Area of Malaysia/Thailand.

At December 31, 2012, exploratory drilling costs capitalized in excess of one year past completion of drilling were incurred as follows (in millions):

2011	$ 404
2010	357
2009	426
2008	392
2007 and prior	228
	$1,807

The capitalized well costs in excess of one year relate to 10 projects. Approximately 36% relates to Block WA-390-P, offshore Western Australia, where development planning and commercial activities, including negotiations with potential liquefaction partners, are ongoing. Successful negotiation with a third party liquefaction partner is necessary before the Corporation can negotiate a gas sales agreement and sanction development of the project. Approximately 36% of the capitalized well costs in excess of one year relates to the Corporation's Pony discovery on Block 468 in the deepwater Gulf of Mexico. In the third quarter of 2012, the Corporation signed an exchange agreement with partners of the adjacent Green Canyon Block 512, which contains the Knotty Head discovery. Under this agreement covering Blocks 468 and 512, Hess was appointed operator and has a 20% working interest in the blocks, now collectively referred to as Stampede. Field development planning for Stampede is progressing and the project is targeted for sanction in 2014. Approximately 14% relates to Area 54, offshore Libya, where force majeure was withdrawn in March 2012 and the Corporation is pursuing commercial options. Approximately 7% relates to offshore Ghana where the Corporation completed drilling its seventh consecutive successful exploration well in February 2013. The Corporation now plans to submit an appraisal plan to the Ghanaian government for approval on or before June 2, 2013. In parallel, the Corporation has begun pre-development studies on the block. The remainder of the capitalized well costs in excess of one year relates to projects where further drilling is planned or development planning and other assessment activities are ongoing to determine the economic and operating viability of the projects.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

7. Goodwill

The changes in the carrying amount of goodwill, all of which relate to the E&P segment, are as follows:

	2012	2011
	(In millions)	
Beginning balance at January 1	**$2,305**	$ 2,408
Dispositions	**(97)**	(103)
Ending balance at December 31	**$2,208**	$2,305

8. Asset Impairments

During 2012, the Corporation recorded total asset impairment charges of $598 million ($360 million after income taxes), including three charges totaling $582 million ($344 million after income taxes) in the E&P segment. As a result of a competitive bidding process, the Corporation obtained additional information relating to the fair value of its interests in the Cotulla area of the Eagle Ford Shale in Texas in February 2013. Based on this information and management's anticipated plan for the assets as of December 31, 2012, the Corporation recorded an impairment charge of $315 million ($192 million after income taxes). The Corporation also recorded charges of $208 million ($116 million after income taxes) related to increases in estimated abandonment liabilities primarily for non-producing properties which resulted in the book value of the properties exceeding their fair value. In addition, the Corporation recorded a charge of $59 million ($36 million after income taxes) in the second quarter related to the disposal of certain Eagle Ford properties as part of an asset exchange with its joint venture partner. In 2012, the Corporation also recorded impairment charges of $16 million relating to certain marketing properties in the M&R segment.

During 2011, the Corporation recorded asset impairment charges of $358 million ($140 million after income taxes) related to increases in the Corporation's estimated abandonment liabilities primarily for non-producing properties which resulted in the book value of the properties exceeding their fair value. During 2010, the Corporation recorded an asset impairment charge of $532 million ($334 million after income taxes) to fully impair the carrying value of its 55% interest in the West Mediterranean Block 1 concession (West Med Block), located offshore Egypt, when the Corporation and its partners notified the Egyptian authorities of their decision to cease exploration activities on the block and to relinquish a significant portion of the block. For both 2011 and 2010, these asset impairments related to the E&P segment.

9. Asset Retirement Obligations

The following table describes changes to the Corporation's asset retirement obligations:

	2012	2011
	(In millions)	
Asset retirement obligations at January 1	**$2,071**	$1,358
Liabilities incurred	**186**	25
Liabilities settled or disposed of	**(324)**	(334)
Accretion expense	**135**	96
Revisions of estimated liabilities	**529**	947
Foreign currency translation	**64**	(21)
Asset retirement obligations at December 31	**2,661**	2,071
Less: Current obligations	**449**	227
Long-term obligations at December 31	**$2,212**	$ 1,844

The revisions in 2012 reflect overall increases in estimated abandonment obligations resulting from changes in the expected scope of operations, increases in the time expected to complete dismantlement activities and updates to service rates. In 2011, the revisions of estimated liabilities reflect an increase in well abandonment obligations resulting from enhanced cement seal verification procedures, changes in scope and timing due to updated work programs and higher service and equipment costs.

Table of Contents

10. Debt and Interest Expense

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

	2012	2011
	(In millions)	
Revolving credit facility, weighted average rate 1.6%	**$ 758**	$ —
Asset-backed credit facility, weighted average rate 0.8%	**600**	350
Short-term credit facilities, weighted average rate 1.5%	**990**	100
Fixed-rate public notes:		
7.0% due 2014	**250**	250
8.1% due 2019	**998**	998
7.9% due 2029	**695**	695
7.3% due 2031	**746**	746
7.1% due 2033	**598**	598
6.0% due 2040	**745**	744
5.6% due 2041	**1,242**	1,242
Total fixed-rate public notes	**5,274**	5,273
Leased floating production system	**180**	7
Other fixed-rate notes, weighted average rate 10.9%, due through 2023	**111**	112
Project lease financing, weighted average rate 5.1%, due through 2014	**78**	90
Pollution control revenue bonds, weighted average rate 5.9%, due through 2034	**53**	53
Fair value adjustments — interest rate hedging	**65**	53
Other debt	**2**	19
Total debt	**8,111**	6,057
Less: Short-term debt and current maturities of long-term debt	**787**	52
Total long-term debt	**$7,324**	$ 6,005

The Corporation has a $4 billion syndicated revolving credit facility that matures in April 2016. This facility can be used for borrowings and letters of credit. Borrowings on the facility bear interest at 1.25% above the London Interbank Offered Rate. A fee of 0.25% per annum is also payable on the amount of the facility. The interest rate and facility fee are subject to adjustment if the Corporation's credit rating changes.

The Corporation has a 364-day asset-backed credit facility securitized by certain accounts receivable from its M&R operations. Under the terms of this financing arrangement, the Corporation has the ability to borrow or issue letters of credit of up to $1 billion, subject to the availability of sufficient levels of eligible receivables. At December 31, 2012, outstanding borrowings under this facility of $600 million were collateralized by a total of approximately $1,050 million of accounts receivable, which are held by a wholly-owned subsidiary. These receivables are only available to pay the general obligations of the Corporation after satisfaction of the outstanding obligations under the asset-backed facility.

During 2012, the Corporation borrowed a net amount of $1,845 million from available credit facilities, which consisted of $758 million from its syndicated revolving credit facility, $890 million from the Corporation's short-term credit facilities and $250 million from its asset-backed credit facility, which was partially offset by net repayments of other debt of $53 million. At December 31, 2012, the Corporation classified as long-term $1,598 million of outstanding borrowings under its short-term facilities, based on availability under its long-term syndicated revolving credit facility.

During 2012, the Corporation recorded a net increase of $173 million in long-term debt related to progress on construction of a leased floating production system to be used at the Tubular Bells project.

At December 31, 2012, the Corporation's fixed-rate public notes have a principal amount of $5,300 million ($5,274 million net of unamortized discount). Interest rates on the outstanding fixed-rate public notes have a weighted average rate of 6.9%.

The aggregate long-term debt maturing during the next five years is as follows (in millions): 2013 — $37; 2014 — $524; 2015 — $6; 2016 — $1,604 and 2017 — $13.

The Corporation's long-term debt agreements, including the revolving credit facility, contain financial covenants that restrict the amount of total borrowings and secured debt. At December 31, 2012, the Corporation is permitted to borrow up to an additional $27.2 billion for the construction or acquisition of assets. The Corporation has the ability to borrow up to an additional $4.9 billion of secured debt at December 31, 2012.

Outstanding letters of credit at December 31 were as follows:

	2012	2011
	(In millions)	
Committed lines*	**$ 463**	$ 1,063
Uncommitted lines*	**283**	462
Revolving credit facility	**—**	173
Total	**$ 746**	$1,698

** Committed and uncommitted lines have expiration dates through 2014.*

Of the letters of credit outstanding at December 31, 2012, totaling $746 million, $141 million relates to contingent liabilities and the remaining $605 million relates to liabilities recorded in the Consolidated Balance Sheet.

The total amount of interest paid (net of amounts capitalized) was $419 million, $383 million and $319 million in 2012, 2011 and 2010, respectively. The Corporation capitalized interest of $28 million, $13 million and $5 million in 2012, 2011 and 2010, respectively.

11. Share-based Compensation

Prior to 2012, the Corporation awarded restricted common stock and stock options under its 2008 Long-term Incentive Plan, as amended. In March 2012, the Corporation began awarding performance share units (PSUs) under this plan. Outstanding restricted stock and PSUs generally vest three years from 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 fifteen peer companies over a three-year performance period ending December 31, 2014. Payouts of the 2012 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 and 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		
	2012	2011	2010	2012	2011	2010
	(In millions)					
Stock options	**$ 34**	$ 51	$ 52	**$ 21**	$ 31	$ 32
Restricted stock	**57**	53	60	**35**	32	37
Performance share units	**8**	—	—	**5**	—	—
Total	**$ 99**	$104	$112	**$ 61**	$ 63	$ 69

Based on share-based compensation awards outstanding at December 31, 2012, unearned compensation expense, before income taxes, will be recognized in future years as follows (in millions): 2013 — $69, 2014 — $43 and 2015 — $8.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The Corporation's share-based compensation activity consisted of the following:

	Performance Share Units		Stock Options		Restricted Stock	
	Performance Share Units	Weighted-Average Price 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)		(In thousands)		(In thousands)	
Outstanding at January 1, 2012	—	$ —	13,570	$ 61.68	2,447	$ 65.38
Granted	425	64.14	48	52.47	1,580	63.50
Exercised	—	—	(212)	49.53	—	—
Vested	—	—	—	—	(883)	56.53
Forfeited	(11)	64.14	(503)	72.00	(240)	67.25
Outstanding at December 31, 2012*	414	$ 64.14	12,903	$ 61.45	2,904	$ 66.89

** Includes 10,789 thousand exercisable options at a weighted average price of $58.99 at December 31, 2012.*

The table below summarizes information regarding the outstanding and exercisable stock options as of December 31, 2012:

	Outstanding Options			Exercisable Options	
Range of Exercise Prices	Options	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price per Share	Options	Weighted-Average Exercise Price per Share
	(In thousands)	(Years)		(In thousands)	
$20.00 – $40.00	1,065	2	$ 27.59	1,065	$ 27.59
$40.01 – $50.00	1,477	3	49.28	1,467	49.30
$50.01 – $60.00	4,153	5	55.12	4,089	55.11
$60.01 – $80.00	2,400	7	60.56	1,596	60.53
$80.01 – $120.00	3,808	7	83.10	2,572	82.72
	12,903	5	$ 61.45	10,789	$ 58.99

The intrinsic value (or the amount by which the market price of the Corporation's common stock exceeds the exercise price of an option) at December 31, 2012 totaled $32 million for both outstanding options and exercisable options. At December 31, 2012, the weighted average remaining term of exercisable options was five years.

The Corporation uses the Black-Scholes model to estimate the fair value of stock options. The following weighted average assumptions were utilized for stock options awarded:

	2012	2011	2010
Risk free interest rate	**0.64%**	1.81%	2.14%
Stock price volatility	**.397**	.395	.390
Dividend yield	**.77%**	.49%	.67%
Expected life in years	**4.5**	4.5	4.5
Weighted average fair value per option granted	**$16.49**	$27.98	$20.18

The risk free interest rate is based on the expected life of the options and is obtained from published sources. The stock price volatility is determined from historical stock prices using the same period as the expected life of the options. The expected stock option life is based on historical exercise patterns.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The Corporation uses a Monte Carlo simulation model to estimate the fair value of PSUs. The following weighted average assumptions were utilized for PSUs awarded:

	2012
Risk free interest rate	0.40%
Stock price volatility	.394
Contractual term in years	3.0
Grant date price of Hess common stock	$64.14

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.

In May 2008, shareholders approved the 2008 Long-term Incentive Plan, which was amended in May 2010 and May 2012 to increase the number of new shares of common stock available for awards. The Corporation also has stock options outstanding under a former plan. At December 31, 2012, the Corporation had 12.4 million shares that remain available for issuance under the 2008 Long-term Incentive Plan, as amended, out of the total of 29 million shares of common stock authorized for issuance under the 2008 Long-term Incentive Plan, as amended.

12. Foreign Currency

Foreign currency gains (losses) before income taxes recorded in the Statement of Consolidated Income amounted to a gain of $37 million in 2012, a loss of $29 million in 2011 and a loss of $5 million in 2010. The after-tax foreign currency translation adjustments recorded in Accumulated other comprehensive income (loss) were an increase to stockholders' equity of $169 million at December 31, 2012 and a reduction to stockholders' equity of $84 million at December 31, 2011.

13. Retirement Plans

The Corporation has funded noncontributory defined benefit pension plans for a significant portion of its employees. In addition, the Corporation has an unfunded supplemental pension plan covering certain employees, which provides incremental payments that would have been payable from the Corporation's 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, the Corporation maintains 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 Corporation's benefit obligations and the fair value of plan assets and shows the funded status of the pension and postretirement medical plans:

	Funded Pension Plans		Unfunded Pension Plan		Postretirement Medical Plan	
	2012	2011	2012	2011	2012	2011
	(In millions)					
Change in benefit obligation						
Balance at January 1	**$1,866**	$ 1,497	**$ 227**	$ 192	**$ 125**	$ 107
Service cost	**64**	49	**10**	9	**7**	6
Interest cost	**81**	81	**7**	8	**5**	5
Actuarial (gain) loss	**134**	294	**13**	31	**2**	9
Benefit payments	**(54)**	(51)	**(2)**	(13)	**(5)**	(2)
Plan settlements*	**—**	—	**(21)**	—	**—**	—
Foreign currency exchange rate changes	**19**	(4)	**—**	—	**—**	—
Balance at December 31	**2,110**	1,866	**234**	227	**134**	125

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	Funded Pension Plans		Unfunded Pension Plan		Postretirement Medical Plan	
	2012	2011	2012	2011	2012	2011
	(In millions)					
Change in fair value of plan assets						
Balance at January 1	**1,493**	1,365	**—**	—	**—**	—
Actual return on plan assets	**155**	(3)	**—**	—	**—**	—
Employer contributions	**150**	185	**23**	13	**5**	2
Benefit payments	**(54)**	(51)	**(2)**	(13)	**(5)**	(2)
Plan settlements*	**—**	—	**(21)**	—	**—**	—
Foreign currency exchange rate changes	**19**	(3)	**—**	—	**—**	—
Balance at December 31	**1,763**	1,493	**—**	—	**—**	—
Funded status (plan assets less than benefit obligations) at December 31	**(347)**	(373)	**(234)**	(227)	**(134)**	(125)
Unrecognized net actuarial losses	**850**	829	**97**	103	**39**	39
Net amount recognized	**$ 503**	$ 456	**$ (137)**	$ (124)	**$ (95)**	$ (86)

** In 2012, the Corporation recorded charges related to plan settlements of $9 million ($5 million after income taxes) due to employee retirements.*

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

	Funded Pension Plans		Unfunded Pension Plan		Postretirement Medical Plan	
	2012	2011	2012	2011	2012	2011
	(In millions)					
Accrued benefit liability	**$ (347)**	$ (373)	**$ (234)**	$ (227)	**$ (134)**	$ (125)
Accumulated other comprehensive loss, pre-tax*	**850**	829	**97**	103	**39**	39
Net amount recognized	**$ 503**	$ 456	**$ (137)**	$ (124)	**$ (95)**	$ (86)

** The after-tax reduction to equity recorded in Accumulated other comprehensive income (loss) for these retirement plans was $639 million at December 31, 2012 and $631 million at December 31, 2011.*

The accumulated benefit obligation for the funded defined benefit pension plans increased to $1,937 million at December 31, 2012 from $1,703 million at December 31, 2011. The accumulated benefit obligation for the unfunded defined benefit pension plan was $216 million at December 31, 2012 and $202 million at December 31, 2011.

Components of net periodic benefit cost for funded and unfunded pension plans and the postretirement medical plan consisted of the following:

	Pension Plans			Postretirement Medical Plan		
	2012	2011	2010	2012	2011	2010
	(In millions)					
Service cost	**$ 74**	$ 58	$ 49	**$ 7**	$ 6	$ 5
Interest cost	**88**	89	86	**5**	5	4
Expected return on plan assets	**(116)**	(109)	(86)	**—**	—	—
Amortization of unrecognized net actuarial losses	**83**	47	48	**2**	2	1
Settlement loss	**9**	—	8	**—**	—	—
Net periodic benefit cost	**$ 138**	$ 85	$ 105	**$ 14**	$ 13	$ 10

The Corporation's 2013 pension and postretirement medical expense is estimated to be approximately $135 million, of which approximately $85 million relates to the amortization of unrecognized net actuarial losses.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The weighted average actuarial assumptions used by the Corporation's funded and unfunded pension plans were as follows:

	2012	2011	2010
Weighted average assumptions used to determine benefit obligations at December 31			
Discount rate	**3.8%**	4.3%	5.3%
Rate of compensation increase	**4.3**	4.3	4.4
Weighted average assumptions used to determine net benefit cost for the years ended December 31			
Discount rate	**4.3**	5.3	5.8
Expected return on plan assets	**7.5**	7.5	7.5
Rate of compensation increase	**4.3**	4.4	4.3

The actuarial assumptions used by the Corporation's postretirement medical plan were as follows:

	2012	2011	2010
Assumptions used to determine benefit obligations at December 31			
Discount rate	**3.1%**	3.9%	4.8%
Initial health care trend rate	**7.3%**	8.0%	8.0%
Ultimate trend rate	**4.8%**	5.0%	5.0%
Year in which ultimate trend rate is reached	**2022**	2018	2017

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.

The Corporation's 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 the Corporation's 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, 2012 and 2011 in accordance with the fair value measurement hierarchy described in Note 1, Summary of Significant Accounting Policies in the notes to the Consolidated Financial Statements:

	Level 1	Level 2	Level 3	Total
		(In millions)		
December 31, 2012				
Cash and short-term investment funds	**$ 2**	**$ 37**	**$ —**	**$ 39**
Equities:				
U.S. equities (domestic)	**534**	**—**	**—**	**534**
International equities (non-U.S.)	**61**	**148**	**—**	**209**
Global equities (domestic and non-U.S.)	**5**	**174**	**—**	**179**
Fixed income:				
Treasury and government issued (a)	**—**	**184**	**2**	**186**
Government related (b)	**—**	**8**	**—**	**8**
Mortgage-backed securities (c)	**—**	**96**	**—**	**96**
Corporate	**1**	**110**	**—**	**111**
Other:				
Hedge funds	**—**	**—**	**255**	**255**
Private equity funds	**—**	**—**	**75**	**75**
Real estate funds	**9**	**—**	**45**	**54**
Diversified commodities funds	**—**	**17**	**—**	**17**
	$ 612	**$ 774**	**$ 377**	**$ 1,763**
December 31, 2011				
Cash and short-term investment funds	$ 2	$ 28	$ —	$ 30
Equities:				
U.S. equities (domestic)	452	—	—	452
International equities (non-U.S.)	50	118	—	168
Global equities (domestic and non-U.S.)	11	149	—	160
Fixed income:				
Treasury and government issued (a)	—	149	1	150
Government related (b)	—	12	2	14
Mortgage-backed securities (c)	—	87	—	87
Corporate	—	96	1	97
Other:				
Hedge funds	—	—	211	211
Private equity funds	—	—	58	58
Real estate funds	7	—	44	51
Diversified commodities funds	—	15	—	15
	$ 522	$ 654	$ 317	$ 1,493

(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. The short-term investment funds 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 are traded actively on exchanges and price quotes for these shares are readily available. Individual equity securities are classified as Level 1. Commingled fund values reflect the NAV per fund share, derived from the quoted prices in active markets of the underlying securities. Equity commingled funds 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.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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. Such prices are monitored and provided by an independent, third-party custodial firm responsible for safekeeping plan assets. Individual fixed income securities are classified as Level 2 or 3. Commingled fund values reflect the NAV per fund share, derived indirectly from observable inputs or from quoted prices in less liquid markets of the underlying securities. Fixed income commingled funds 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, 2011	$ 7	$ 187	$ 40	$ 32	$ 266
Actual return on plan assets:					
Related to assets held at December 31, 2011	—	(5)	9	2	6
Related to assets sold during 2011	—	2	—	—	2
Purchases, sales or other settlements	(3)	27	9	10	43
Net transfers in (out) of Level 3	—	—	—	—	—
Balance at December 31, 2011	4	211	58	44	317
Actual return on plan assets:					
Related to assets held at December 31, 2012	**—**	**13**	**5**	**1**	**19**
Related to assets sold during 2012	**—**	**—**	**—**	**—**	**—**
Purchases, sales or other settlements	**(1)**	**31**	**12**	**—**	**42**
Net transfers in (out) of Level 3	**(1)**	**—**	**—**	**—**	**(1)**
Balance at December 31, 2012	**$ 2**	**$ 255**	**$ 75**	**$ 45**	**$ 377**

* *Fixed Income includes treasury and government issued, government related, mortgage-backed and corporate securities.*

The Corporation has budgeted contributions of approximately $140 million to its funded pension plans in 2013.

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):

2013	$ 101
2014	98
2015	102
2016	119
2017	113
Years 2018 to 2022	677

The Corporation also contributes to several defined contribution plans for eligible employees. Employees may contribute a portion of their compensation to the plans and the Corporation matches a portion of the employee contributions. The Corporation recorded expense of $40 million in 2012, $28 million in 2011 and $24 million in 2010 for contributions to these plans.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

14. Income Taxes

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

	2012	2011	2010
		(In millions)	
United States Federal			
Current	**$ 30**	$ 202	$ 151
Deferred	**(317)**	(588)	(309)
State	**46**	17	46
	(241)	(369)	(112)
Foreign			
Current	**2,019**	1,185	1,515
Deferred	**(218)**	(60)	(230)
	1,801	1,125	1,285
Adjustment of deferred tax liability for foreign income tax rate change*	**115**	29	—
Total provision for income taxes	**$1,675**	$ 785	$ 1,173

** Represents the effect of the United Kingdom (UK) supplementary income tax rate change to 20% from 32% on dismantlement expenses in July 2012. Also reflects the July 2011 increase in the supplementary tax on petroleum operations to 32% from 20% in the UK.*

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

	2012	2011	2010
		(In millions)	
United States (a)	**$ (211)**	$ 211	$ (108)
Foreign (b)	**3,949**	2,250	3,419
Total income before income taxes	**$3,738**	$2,461	$3,311

(a) Includes substantially all of the Corporation's interest expense and the results of hedging activities.
(b) Foreign income includes the Corporation's Virgin Islands and other operations located outside of the United States.

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

	2012	2011
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	**$ (4,951)**	$ (3,742)
Other	**(36)**	(125)
Total deferred tax liabilities	**(4,987)**	(3,867)
Deferred tax assets		
Net operating loss carryforwards	**1,985**	1,204
Tax credit carryforwards	**373**	396
Property, plant and equipment and investments	**3,165**	2,217
Investment in HOVENSA	**—**	331
Accrued compensation, other liabilities and deferred credits	**976**	508
Asset retirement obligations	**508**	438
Other	**313**	332
Total deferred tax assets	**7,320**	5,426
Valuation allowances	**(1,282)**	(1,071)
Total deferred tax assets, net	**6,038**	4,355
Net deferred tax assets	**$ 1,051**	$ 488

At December 31, 2012, the Corporation has recognized a gross deferred tax asset related to net operating loss carryforwards of $1,985 million before application of the valuation allowances. The deferred tax asset is comprised of $1,637 million attributable to foreign net operating losses, which begin to expire in 2020, $91 million attributable to United States federal operating losses which begin to expire in 2020 and $257 million attributable to losses in various states which begin to expire in 2013. The deferred tax asset attributable to foreign net operating losses, net of valuation allowances, is $1,056 million, substantially all of which relates to loss carryforwards in Norway and Indonesia. At December 31, 2012, the Corporation has federal, state and foreign alternative minimum tax credit carryforwards of $148 million, which can be carried forward indefinitely and approximately $1 million of other business credit carryforwards. Foreign tax credit carryforwards, which begin to expire in 2016, total $224 million. Included within Property, plant and equipment and investments in the foregoing table are taxes deferred, resulting from intercompany transactions eliminated in consolidation related to transfers of property, plant and equipment remaining within the consolidated group.

In the Consolidated Balance Sheet, deferred tax assets and liabilities from the preceding table are netted by taxing jurisdiction, combined with taxes deferred on intercompany transactions, and are recorded at December 31 as follows:

	2012	2011
	(In millions)	
Other current assets	**$ 596**	$ 398
Deferred income taxes (long-term asset)	**3,126**	2,941
Accrued liabilities	**(9)**	(8)
Deferred income taxes (long-term liability)	**(2,662)**	(2,843)
Net deferred tax assets	**$ 1,051**	$ 488

The difference between the Corporation's effective income tax rate and the United States statutory rate is reconciled below:

	2012	2011	2010
United States statutory rate	**35.0%**	35.0%	35.0%
Effect of foreign operations*	**11.3**	(4.1)	9.4
State income taxes, net of Federal income tax	**0.8**	0.4	0.9
Change in enacted tax rate	**3.1**	1.2	—
Gains on asset sales	**(4.8)**	(5.0)	(10.4)
Effect of equity loss and operations related to HOVENSA	—	2.8	3.1
Other	**(0.6)**	1.6	(2.6)
Total	**44.8%**	31.9%	35.4%

** The variance in effective income tax rates attributable to the effect of foreign operations primarily resulted from the suspension of operations in Libya for most of 2011.*

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

	2012	2011
	(In millions)	
Balance at January 1	**$ 415**	$ 400
Additions based on tax positions taken in the current year	**132**	62
Additions based on tax positions of prior years	**45**	20
Reductions based on tax positions of prior years	**(33)**	(8)
Reductions due to settlements with taxing authorities	**(30)**	(59)
Reductions due to lapse of statutes of limitation	**(6)**	—
Balance at December 31	**$ 523**	$ 415

At December 31, 2012, the unrecognized tax benefits include $466 million, which if recognized, would affect the Corporation's effective income tax rate. Over the next 12 months, it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $25 million to $35 million due to settlements with taxing authorities and lapsing of statutes of limitation. The Corporation had accrued interest and penalties related to unrecognized tax benefits of $60 million as of December 31, 2012 and $42 million as of December 31, 2011.

Table of Contents

The Corporation has not recognized deferred income taxes for that portion of undistributed earnings of foreign subsidiaries expected to be indefinitely reinvested in foreign operations. The Corporation had undistributed earnings from foreign subsidiaries expected to be indefinitely reinvested in foreign operations of approximately $6.7 billion at December 31, 2012. If these earnings were not indefinitely reinvested, a deferred tax liability of approximately $2.3 billion would be recognized, not accounting for the utilization of foreign tax credits in the United States.

The Corporation and its subsidiaries file income tax returns in the United States and various foreign jurisdictions. The Corporation is no longer subject to examinations by income tax authorities in most jurisdictions for years prior to 2005.

Income taxes paid (net of refunds) in 2012, 2011 and 2010 amounted to $1,822 million, $1,384 million and $1,450 million, respectively.

15. Outstanding and Weighted Average Common Shares

The following table provides the changes in the Corporation's outstanding common shares:

	2012	2011	2010
		(In millions)	
Balance at January 1	**340.0**	337.7	327.2
Activity related to restricted common stock awards, net	**1.3**	0.6	0.8
Stock options	**0.2**	1.7	1.1
Issued for an acquisition*	**—**	—	8.6
Balance at December 31	**341.5**	340.0	337.7

** See Note 3, Acquisitions in the notes to the Consolidated Financial Statements.*

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

	2012	2011	2010
	(In millions, except per share amounts)		
Net income attributable to Hess Corporation	**$ 2,025**	$ 1,703	$ 2,125
Weighted average common shares:			
Basic	**338.4**	336.9	326.0
Effect of dilutive securities			
Stock options	**0.8**	1.6	0.8
Restricted common stock	**1.1**	1.4	1.5
Diluted	**340.3**	339.9	328.3
Net income per share:			
Basic	**$ 5.98**	$ 5.05	$ 6.52
Diluted	**$ 5.95**	$ 5.01	$ 6.47

The weighted average common shares used in the diluted earnings per share calculations exclude the effect of approximately 9.2 million, 3.5 million and 5.2 million out-of-the-money stock options for 2012, 2011 and 2010, respectively, and 414,175 PSUs for 2012 based on the Corporation's TSR through December 31, 2012. Cash dividends declared on common stock totaled $0.40 per share ($0.10 per quarter) during 2012, 2011 and 2010.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

16. Leased Assets

The Corporation and certain of its subsidiaries lease gasoline stations, drilling rigs, tankers, office space and other assets for varying periods under contractual obligations accounted for as operating leases. Certain operating leases provide an option to purchase the related property at fixed prices. At December 31, 2012, 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):

2013	$ 700
2014	604
2015	227
2016	127
2017	125
Remaining years	1,060
Total minimum lease payments	2,843
Less: Income from subleases	43
Net minimum lease payments	$ 2,800

Operating lease expenses for drilling rigs used to drill development wells and successful exploration wells are capitalized.

Rental expense was as follows:

	2012	2011	2010
		(In millions)	
Total rental expense	**$ 375**	$ 348	$ 273
Less: Income from subleases	**15**	12	13
Net rental expense	**$ 360**	$ 336	$ 260

17. Guarantees and Contingencies

At December 31, 2012, the Corporation has $141 million in letters of credit for which it is contingently liable. The Corporation also has a contingent purchase obligation to acquire the remaining interest in WilcoHess, a retail gasoline station joint venture. This contingent obligation, which expires in April 2014, was approximately $210 million at December 31, 2012.

The Corporation is subject to loss contingencies with respect to various lawsuits, claims and other proceedings, including environmental matters. A liability is recognized in the Corporation's consolidated financial statements when it is probable 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, the Corporation discloses the nature of those contingencies .

The Corporation, along with many other companies engaged in refining and marketing of gasoline, has 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 United States against producers of MTBE and petroleum refiners who produced gasoline containing MTBE, including the Corporation. 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. In 2008, the majority of the cases against the Corporation were settled. In 2010 and 2011, additional cases were settled including an action brought in state court by the State of New Hampshire. Two cases brought by the State of New Jersey and the Commonwealth of Puerto Rico remain unresolved. In 2007, a pre-tax charge of $40 million was recorded to cover all of the known MTBE cases against the Corporation.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The Corporation is from time to time involved in other judicial and administrative proceedings, including proceedings relating to other environmental matters. The Corporation 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 the financial condition, results of operations or cash flows of the Corporation.

18. Segment Information

The Corporation has two operating segments that comprise the structure used by senior management to make key operating decisions and assess performance. These are (1) Exploration and Production and (2) Marketing and Refining. The following table presents financial data by segment:

	Exploration and Production	Marketing and Refining	Corporate and Interest	Consolidated (a)
		(In millions)		
2012				
Operating revenues				
Total operating revenues (b)	**$ 12,245**	**$ 25,520**	**$ 2**	
Less: Transfers between affiliates	**75**	**1**	**—**	
Operating revenues from unaffiliated customers	**$ 12,170**	**$ 25,519**	**$ 2**	**$ 37,691**
Net income (loss) attributable to Hess Corporation	**$ 2,212**	**$ 231**	**$ (418)**	**$ 2,025**
Interest expense	**$ —**	**$ —**	**$ 419**	**$ 419**
Depreciation, depletion and amortization	**2,853**	**83**	**13**	**2,949**
Asset impairments	**582**	**16**	**—**	**598**
Provision (benefit) for income taxes	**1,793**	**145**	**(263)**	**1,675**
Investments in affiliates	**75**	**368**	**—**	**443**
Identifiable assets	**37,687**	**5,139**	**615**	**43,441**
Capital employed (c)	**26,339**	**2,570**	**405**	**29,314**
Capital expenditures	**7,676**	**113**	**6**	**7,795**
2011				
Operating revenues				
Total operating revenues (b)	$ 10,646	$ 27,936	$ 1	
Less: Transfers between affiliates	116	1	—	
Operating revenues from unaffiliated customers	$ 10,530	$ 27,935	$ 1	$ 38,466
Net income (loss) attributable to Hess Corporation	$ 2,675	$ (584)	$ (388)	$ 1,703
Loss from equity investment in HOVENSA L.L.C.	$ —	$ (1,073)	$ —	$ (1,073)
Interest expense	—	—	383	383
Depreciation, depletion and amortization	2,305	88	13	2,406
Asset impairments	358	—	—	358
Provision (benefit) for income taxes	1,313	(273)	(255)	785
Investments in affiliates	97	287	—	384
Identifiable assets	32,323	6,302	511	39,136
Capital employed (c)	22,699	2,337	(387)	24,649
Capital expenditures	6,888	115	3	7,006

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	Exploration and Production	Marketing and Refining	Corporate and Interest	Consolidated (a)
	(In millions)			
2010				
Operating revenues				
Total operating revenues (b)	$ 9,119	$ 24,885	$ 1	
Less: Transfers between affiliates	143	—	—	
Operating revenues from unaffiliated customers	$ 8,976	$ 24,885	$ 1	$ 33,862
Net income (loss) attributable to Hess Corporation	$ 2,736	$ (231)	$ (380)	$ 2,125
Loss from equity investment in HOVENSA L.L.C.	$ —	$ (522)	$ —	$ (522)
Interest expense	—	—	361	361
Depreciation, depletion and amortization	2,222	82	13	2,317
Asset impairments	532	—	—	532
Provision (benefit) for income taxes	1,417	4	(248)	1,173
Investments in affiliates	57	386	—	443
Identifiable assets	28,242	6,377	777	35,396
Capital employed (c)	19,803	2,715	(126)	22,392
Capital expenditures	5,394	82	16	5,492

(a) *After elimination of transactions between affiliates, which are valued at approximate market prices.*

(b) *Sales and operating revenues are reported net of excise and similar taxes in the Statement of Consolidated Income, which amounted to approximately $2,580 million, $2,350 million and $2,200 million in 2012, 2011 and 2010, respectively.*

(c) *E&P, M&R and Corporate only. Calculated as equity plus debt.*

Financial information by major geographic area is as follows:

	United States	Europe	Africa	Asia and Other	Consolidated
			(In millions)		
2012					
Operating revenues	**$ 30,784**	**$ 2,530**	**$ 2,484**	**$ 1,893**	**$ 37,691**
Property, plant and equipment (net)	**14,233**	**8,172***	**2,517**	**3,885**	**28,807**
2011					
Operating revenues	$ 31,813	$ 3,137	$ 1,782	$ 1,734	$ 38,466
Property, plant and equipment (net)	11,490	6,826*	2,355	4,041	24,712
2010					
Operating revenues	$ 28,066	$ 2,109	$ 2,271	$ 1,416	$ 33,862
Property, plant and equipment (net)	8,343	6,764*	2,573	3,447	21,127

** Of the total Europe property, plant and equipment (net), Norway represented $6,426 million, $5,031 million and $5,002 million in 2012, 2011 and 2010, respectively.*

19. Related Party Transactions

The following table presents the Corporation's related party transactions:

	2012	2011	2010
		(In millions)	
Purchases:			
HOVENSA (a)	**$ 145**	$ 3,806	$ 4,307
Bayonne Energy Center LLC (b)	**20**	—	—
Sales:			
WilcoHess	**3,058**	2,898	2,113
HOVENSA	**191**	710	607

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(a) Following the closure of HOVENSA's refinery in St. Croix in January 2012, the Corporation no longer purchases 50% of HOVENSA's production of refined petroleum products, after any sales to unaffiliated parties.

(b) Represents payments under a 15 year tolling agreement with remaining total minimum payments of approximately $395 million.

The following table presents the Corporation's related party accounts receivable (payable) at December 31:

	2012	2011
	(In millions)	
WilcoHess	**$119**	$127
Bayonne Energy Center LLC	**(3)**	—
HOVENSA, net*	**—**	(22)

** Excludes the Corporation's planned funding commitments of $487 million at December 31, 2011 related to the refinery shutdown, which was paid in 2012.*

20. Risk Management and Trading Activities

In the normal course of its business, the Corporation is exposed to commodity risks related to changes in the prices of crude oil, natural gas, refined petroleum products and electricity, as well as to changes in interest rates and foreign currency values. In the disclosures that follow, risk management activities are referred to as energy marketing and corporate risk management activities. The Corporation also has trading operations, principally through a 50% voting interest in a consolidated partnership, which trades energy-related commodities, securities and derivatives. These activities are also exposed to commodity price risks primarily related to the prices of crude oil, natural gas, refined petroleum products and electricity.

The Corporation maintains a control environment under the direction of its chief risk officer and through its corporate risk policy, which the Corporation's senior management has approved. Controls include volumetric, term and value at risk limits. The chief risk officer must approve the trading of new instruments or commodities. Risk limits are monitored and reported on a daily basis to business units and senior management. The Corporation's risk management department also performs independent price verifications (IPV's) of sources of fair values, validations of valuation models and analyzes changes in fair value measurements on a daily, monthly and/or quarterly basis. These controls apply to all of the Corporation's risk management and trading activities, including the consolidated trading partnership. The Corporation's treasury department is responsible for administering foreign exchange rate and interest rate hedging programs using similar controls and processes, where applicable.

The Corporation's risk management department, in performing the IPV procedures, utilizes independent sources and valuation models that are specific to the individual contracts and pricing locations to identify positions that require adjustments to better reflect the market. This review is performed quarterly and the results are presented to the chief risk officer and senior management. The IPV process considers the reliability of the pricing services through assessing the number of available quotes, the frequency at which data is available and, where appropriate, the comparability between pricing sources.

Following is a description of the Corporation's activities that use derivatives as part of their operations and strategies. Derivatives include both financial instruments and forward purchase and sale contracts. Gross notional amounts of both long and short positions are presented in the volume tables 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.

Energy Marketing Activities: In its energy marketing activities, the Corporation sells refined petroleum products, natural gas and electricity principally to commercial and industrial businesses at fixed and floating prices for varying periods of time. Commodity contracts such as futures, forwards, swaps and options, together with physical assets such as storage and pipeline capacity, are used to obtain supply and reduce margin volatility or lower costs related to sales contracts with customers.

The gross volumes of the Corporation's energy marketing commodity contracts outstanding at December 31 were as follows:

	2012	2011
Crude oil and refined petroleum products (millions of barrels)	**26**	28
Natural gas (millions of mcf)	**2,938**	2,616
Electricity (millions of megawatt hours)	**278**	244

The changes in fair value of certain energy marketing commodity contracts that are not designated as hedges are recognized currently in earnings. Revenues from the sales contracts are recognized in Sales and other operating revenues in the Statement of Consolidated Income, while supply contract purchases and net settlements from financial derivatives related to these energy marketing activities are recognized in Cost of products sold in the Statement of Consolidated Income. Net realized and unrealized pre-tax gains on derivative contracts not designated as hedges amounted to $127 million in 2012, $65 million in 2011 and $247 million in 2010.

At December 31, 2012, a portion of energy marketing commodity contracts are designated as cash flow hedges to hedge variability of expected future cash flows of forecasted supply transactions. The length of time over which the Corporation hedges exposure to variability in future cash flows is predominantly one year or less. For contracts outstanding at December 31, 2012, the maximum duration was approximately two years.

The Corporation records the effective portion of changes in the fair value of cash flow hedges as a component of Accumulated other comprehensive income (loss) in the Consolidated Balance Sheet and then reclassifies amounts to Cost of products sold in the Statement of Consolidated Income as the hedged transactions are recognized in earnings. The after-tax deferred losses relating to energy marketing activities recorded in Accumulated other comprehensive income (loss) were $22 million and $64 million at December 31, 2012 and 2011, respectively. The Corporation estimates that a loss of approximately $14 million will be reclassified into earnings over the next twelve months. During 2012, 2011 and 2010, the Corporation reclassified after-tax losses from Accumulated other comprehensive income (loss) of $52 million, $105 million and $318 million ($85 million, $172 million and $527 million of pre-tax losses), respectively.

The amounts of ineffectiveness recognized immediately in Cost of products sold were a loss of $4 million in 2011 and a gain of $2 million in 2010. There was no ineffectiveness in 2012. The pre-tax amount of deferred hedge losses is reflected in Accounts payable and the related income tax benefits are recorded as deferred income tax assets, which are included in Other current assets in the Consolidated Balance Sheet.

Corporate Risk Management Activities: Corporate risk management activities include transactions designed to reduce risk in the selling prices of crude oil, refined petroleum products or natural gas produced by the Corporation or to reduce 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 the Corporation's crude oil, refined petroleum products or natural gas production. Forward contracts may also be used to purchase certain currencies in which the Corporation does business with the intent of reducing exposure to foreign currency fluctuations. These forward contracts comprise various currencies including the British Pound and Thai Baht. Interest rate swaps may be used to convert interest payments on certain long-term debt from fixed to floating rates.

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

	2012	2011
Commodity, primarily crude oil (millions of barrels)	**1**	51
Foreign exchange (millions of U.S. Dollars)	**$1,285**	$ 900
Interest rate swaps (millions of U.S. Dollars)	**$ 880**	$ 895

During 2008, the Corporation closed Brent crude oil cash flow hedges covering 24,000 barrels per day through 2012, by entering into offsetting contracts with the same counterparty. As a result, the valuation of those contracts was no longer subject to change due to price fluctuations. The deferred hedge losses as of the date that the hedges were closed were recorded in earnings as the hedged transactions occurred. For 2012, the Corporation entered into Brent crude oil hedges using fixed-price swap contracts to hedge the variability of forecasted future cash flows from 120,000 barrels per day of crude oil sales volumes for the full year. The average price for these hedges was $107.70 per barrel. Both of these hedge programs matured as of December 31, 2012. Realized losses from E&P hedging activities decreased Sales and other operating revenues by $688 million in 2012, $517 million in 2011 and $533 million in 2010 ($431 million, $327 million and $338 million after-taxes, respectively). The amounts of ineffectiveness related to Brent crude oil hedges were a loss of $9 million in 2012, a gain of $9 million in 2011 and zero in 2010. The after-tax deferred losses in Accumulated other comprehensive income (loss) related to Brent crude oil hedges was $286 million at December 31, 2011. In January and February of 2013, the Corporation entered into new Brent crude oil hedges covering 90,000 barrels per day for the remainder of 2013 at an average price of approximately $109.70 per barrel.

At December 31, 2012 and 2011, the Corporation had interest rate swaps with gross notional amounts of $880 million and $895 million, respectively, which were designated as fair value hedges. 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. For the years ended December 31, 2012 and 2011, the Corporation recorded increases of $12 million and $45 million (excluding accrued interest), respectively, in the fair value of interest rate swaps and a corresponding adjustment in the carrying value of the hedged fixed-rate debt.

Gains or losses on foreign exchange contracts not designated as hedges are recognized immediately in Other, net in Revenues and non-operating income in the Statement of Consolidated Income.

Net realized and unrealized pre-tax gains (losses) on derivative contracts used for Corporate risk management and not designated as hedges amounted to the following:

	2012	2011	2010
		(In millions)	
Commodity	**$ 1**	$ 1	$ (7)
Foreign exchange	**43**	(15)	(7)
Total	**$ 44**	$ (14)	$ (14)

Trading Activities: Trading activities are conducted principally through a trading partnership in which the Corporation has a 50% voting interest. This consolidated entity operates to generate earnings through various strategies primarily using energy-related commodities, securities and derivatives. The Corporation also takes trading positions for its own account. The information that follows represents 100% of the trading partnership and the Corporation's proprietary trading accounts.

The gross volumes of derivative contracts outstanding relating to trading activities at December 31, were as follows:

	2012	2011
Commodity		
Crude oil and refined petroleum products (millions of barrels)	**1,179**	2,169
Natural gas (millions of mcf)	**3,377**	4,203
Electricity (millions of megawatt hours)	**19**	304
Foreign exchange (millions of U.S. Dollars)	**$ 412**	$ 581
Other		
Interest rate (millions of U.S. Dollars)	**$ 167**	$ 182
Equity securities (millions of shares)	**14**	16

Pre-tax unrealized and realized gains (losses) recorded in Sales and other operating revenues in the Statement of Consolidated Income from trading activities amounted to the following:

	2012	2011	2010
		(In millions)	
Commodity	**$104**	$ 44	$ 88
Foreign exchange	**3**	—	5
Other	**10**	(28)	10
Total	**$117**	$ 16	$103

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Fair Value Measurements: The gross and net fair values of the Corporation's risk management and trading derivative instruments were as follows:

	Accounts Receivable	Accounts Payable
	(In millions)	
December 31, 2012		
Derivative contracts designated as hedging instruments		
Commodity	**$ 65**	**$ (124)**
Interest rate and other	**72**	**(2)**
Total derivative contracts designated as hedging instruments	**137**	**(126)**
Derivative contracts not designated as hedging instruments*		
Commodity	**3,188**	**(3,188)**
Foreign exchange	**14**	**—**
Other	**14**	**(8)**
Total derivative contracts not designated as hedging instruments	**3,216**	**(3,196)**
Gross fair value of derivative contracts	**3,353**	**(3,322)**
Master netting arrangements	**(2,750)**	**2,750**
Cash collateral (received) posted	**(34)**	**5**
Net fair value of derivative contracts	**$ 569**	**$ (567)**
December 31, 2011		
Derivative contracts designated as hedging instruments		
Commodity	$ 181	$ (216)
Interest rate and other	61	(3)
Total derivative contracts designated as hedging instruments	242	(219)
Derivative contracts not designated as hedging instruments*		
Commodity	9,350	(9,823)
Foreign exchange	6	(21)
Other	12	(24)
Total derivative contracts not designated as hedging instruments	9,368	(9,868)
Gross fair value of derivative contracts	9,610	(10,087)
Master netting arrangements	(7,962)	7,962
Cash collateral (received) posted	(121)	117
Net fair value of derivative contracts	$ 1,527	$ (2,008)

** Includes trading derivatives and derivatives used for risk management.*

The Corporation generally enters into master netting arrangements to mitigate counterparty credit risk. Master netting arrangements are standardized contracts that govern all specified transactions with the same counterparty and allow the Corporation to terminate all contracts upon occurrence of certain events, such as the counterparty's default or bankruptcy. Where these arrangements provide the right of offset and the Corporation's intent and practice is to offset amounts in the case of contract terminations, the Corporation records fair value on a net basis.

Table of Contents

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The Corporation determines fair value in accordance with the fair value measurements accounting standard which established a hierarchy that categorizes the sources of 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). The Corporation's net physical derivative and financial assets and (liabilities) that are measured at fair value based on this hierarchy were as follows:

	Level 1	Level 2	Level 3	Collateral and counterparty netting	Balance
			(In millions)		
December 31, 2012					
Assets					
Derivative contracts					
Commodity	**$ 94**	**$ 445**	**$ 243**	**$ (190)**	**$ 592**
Interest rate and other	**6**	**86**	**1**	**(1)**	**92**
Collateral and counterparty netting	**(23)**	**(54)**	**(4)**	**(34)**	**(115)**
Total derivative contracts	**77**	**477**	**240**	**(225)**	**569**
Other assets measured at fair value on a recurring basis	**5**	**49**	**—**	**(2)**	**52**
Total assets measured at fair value on a recurring basis	**$ 82**	**$ 526**	**$ 240**	**$ (227)**	**$ 621**
Liabilities					
Derivative contracts					
Commodity	**$ (83)**	**$ (657)**	**$ (101)**	**$ 190**	**$ (651)**
Other	**(1)**	**(2)**	**—**	**1**	**(2)**
Collateral and counterparty netting	**23**	**54**	**4**	**5**	**86**
Total derivative contracts	**(61)**	**(605)**	**(97)**	**196**	**(567)**
Other liabilities measured at fair value on a recurring basis	**(40)**	**(2)**	**(2)**	**2**	**(42)**
Total liabilities measured at fair value on a recurring basis	**$ (101)**	**$ (607)**	**$ (99)**	**$ 198**	**$ (609)**
Other fair value measurement disclosures					
Long-term debt*	**$ —**	**$ (8,887)**	**$ —**	**$ —**	**$ (8,887)**
December 31, 2011					
Assets					
Derivative contracts					
Commodity	$ 135	$ 1,188	$ 511	$ (67)	$ 1,767
Interest rate and other	—	66	—	—	66
Collateral and counterparty netting	(33)	(148)	(4)	(121)	(306)
Total derivative contracts	102	1,106	507	(188)	1,527
Other assets measured at fair value on a recurring basis	7	34	—	(2)	39
Total assets measured at fair value on a recurring basis	$ 109	$ 1,140	$ 507	$ (190)	$ 1,566
Liabilities					
Derivative contracts					
Commodity	$ (191)	$ (1,501)	$ (650)	$ 67	$ (2,275)
Foreign exchange	—	(15)	—	—	(15)
Other	—	(18)	(2)	—	(20)
Collateral and counterparty netting	33	148	4	117	302
Total derivative contracts	(158)	(1,386)	(648)	184	(2,008)
Other liabilities measured at fair value on a recurring basis	—	(52)	(2)	2	(52)
Total liabilities measured at fair value on a recurring basis	$ (158)	$ (1,438)	$ (650)	$ 186	$ (2,060)
Other fair value measurement disclosures					
Long-term debt*	$ —	$ (7,317)	$ —	$ —	$ (7,317)

** Long-term debt, including current maturities, had a carrying value of $7,361 million and $6,040 million at December 31, 2012 and 2011, respectively.*

Table of Contents

In addition to the financial assets and (liabilities) disclosed in the tables above, the Corporation had other short-term financial instruments, primarily cash equivalents and accounts receivable and payable, for which the carrying value approximated their fair value at December 31, 2012 and December 31, 2011.

The following table provides total net transfers into and out of each level of the fair value hierarchy:

	2012	2011
	(In millions)	
Transfers into Level 1	**$ 251**	$ (17)
Transfers out of Level 1	**210**	297
	$ 461	$ 280
Transfers into Level 2	**$ (234)**	$ —
Transfers out of Level 2	**(293)**	(97)
	$ (527)	$ (97)
Transfers into Level 3	**$ 99**	$ (114)
Transfers out of Level 3	**(33)**	(69)
	$ 66	$ (183)

The Corporation's policy is to recognize transfers in and transfers out as of the end of the reporting period. Transfers between levels result from the passage of time as contracts move closer to their maturities, fluctuations in the market liquidity for certain contracts and/or changes in the level of significance of fair value measurement inputs.

The following table provides changes in physical derivative and financial assets and liabilities that are measured at fair value based on Level 3 inputs:

	2012	2011
	(In millions)	
Balance at January 1	**$ (143)**	$ 412
Unrealized pre-tax gains (losses)		
Included in earnings (a)	**(78)**	(52)
Included in other comprehensive income (b)	**44**	25
Purchases (c)	**247**	2,294
Sales (c)	**(266)**	(2,524)
Settlements (d)	**271**	(115)
Transfers into Level 3	**99**	(114)
Transfers out of Level 3	**(33)**	(69)
Balance at December 31	**$ 141**	$ (143)

(a) The unrealized pre-tax gains (losses) included in earnings for 2012 are comprised of $(44) million reflected in Sales and other operating revenues and $(34) million reflected in Cost of products sold in the Statement of Consolidated Income.

(b) The unrealized pre-tax gains (losses) included in Other comprehensive income are reflected in the Net change in fair value of cash flow hedges in the Statement of Consolidated Comprehensive Income.

(c) Purchases and sales primarily represent option premiums paid or received, respectively, during the reporting period.

(d) Settlements represent realized gains and (losses) on derivatives settled during the reporting period.

The significant unobservable inputs used in Level 3 fair value measurements for the Corporation's physical commodity contracts and derivative instruments primarily include less liquid delivered locations for physical commodity contracts or volatility assumptions for out-of-the-money options. The following table provides information about the Corporation's significant recurring unobservable inputs used in the Level 3 fair value measurements. Fair value measurements for all recurring inputs were performed using a combination of market and income approach techniques. Natural gas contracts are usually quoted and transacted using basis pricing relative to an active pricing location (e.g., Henry Hub), for which price inputs represent the approximate value of differences in geography and local market conditions. All other price inputs below represent full contract prices. Significant changes in any of the inputs below, independent or correlated, may result in a different fair value.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	Unit of Measurement	Range / Weighted Average
December 31, 2012		
Assets		
Commodity contracts with a fair value of $243 million		
Contract prices		
Crude oil and refined petroleum products	$ / bbl (a)	$79.35 - 144.27 / 113.06
Electricity	$ / MWH (b)	$23.37 - 79.27 / 40.81
Basis prices		
Natural gas	$ / MMBTU (c)	$(0.47) - 6.66 / 0.39
Contract volatilities		
Crude oil and refined petroleum products	%	23.00 - 27.00 / 26.00
Natural gas	%	21.00 - 36.00 / 25.00
Electricity	%	18.00 - 40.00 / 28.00
Liabilities		
Commodity contracts with a fair value of $101 million		
Contract prices		
Crude oil and refined petroleum products	$ / bbl (a)	$83.49 - 133.38 / 109.94
Electricity	$ / MWH (b)	$25.01 - 72.60 / 40.38
Basis prices		
Natural gas	$ / MMBTU (c)	$(0.72) - 6.66 / 1.26
Contract volatilities		
Crude oil and refined petroleum products	%	24.00 - 27.00 / 26.00
Natural gas	%	21.00 - 28.00 / 22.00

(a) Price per barrel.
(b) Price per megawatt hour.
(c) Price per million British thermal units.

Credit Risk: The Corporation is 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. The Corporation's net receivables at December 31, 2012 are concentrated with the following counterparty and customer industry segments: Integrated Oil Companies —23%, Refiners —15%, Government Entities —11%, Real Estate —8%, Services —8% and Manufacturing —6%. The Corporation reduces its risk related to certain counterparties by using master netting arrangements and requiring collateral, generally cash or letters of credit. The Corporation records the cash collateral received or posted as an offset to the fair value of derivatives executed with the same counterparty. At December 31, 2012 and 2011, the Corporation held cash from counterparties of $34 million and $121 million, respectively. The Corporation posted cash to counterparties at December 31, 2012 and 2011 of $5 million and $117 million, respectively.

At December 31, 2012, the Corporation had outstanding letters of credit totaling $746 million, primarily issued to satisfy margin requirements. Certain of the Corporation's agreements also contain contingent collateral provisions that could require the Corporation to post additional collateral if the Corporation's credit rating declines. As of December 31, 2012, the net liability related to derivatives with contingent collateral provisions was approximately $435 million. There was no cash collateral posted on those derivatives. At December 31, 2012, all three major credit rating agencies that rate the Corporation's debt had assigned an investment grade rating. If two of the three agencies were to downgrade the Corporation's rating to below investment grade, as of December 31, 2012, the Corporation would be required to post additional collateral of approximately $275 million.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

21. Subsequent Events

In January 2013, the Corporation completed the sale of its interests in the Beryl fields in the United Kingdom North Sea for cash proceeds of approximately $440 million. The Corporation announced in January 2013 its decision to cease refining operations at its Port Reading facility in February and pursue the sale of its terminal network.

On January 29, 2013, Elliott Management Corporation (Elliott) sent a letter to Hess shareholders informing them that affiliates of Elliott beneficially own 4 percent of the outstanding common stock of the Corporation and are nominating five individuals for election as directors at the Corporation's 2013 Annual Meeting. Among other things, Elliott stated its view that Hess should (1) spin off the Corporation's Bakken assets along with the Eagle Ford and Utica acreage; (2) divest the Corporation's downstream assets and place midstream assets into a master limited partnership (MLP) or real estate investment trust (REIT) structure; and (3) divest assets from the Corporation's remaining international portfolio. The Corporation is in the process of reviewing Elliott's proposals with the Board and its advisors and intends to respond in the near future.

Table of Contents

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTARY OIL AND GAS DATA (UNAUDITED)

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.

The Corporation produces crude oil, natural gas liquids and/or natural gas principally in Algeria, Azerbaijan, Denmark, Equatorial Guinea, Indonesia, Libya, Malaysia, Norway, Russia, Thailand, the United Kingdom and the United States. Exploration activities are also conducted, or are planned, in additional countries.

Costs Incurred in Oil and Gas Producing Activities

For the Years Ended December 31	Total	United States	Europe (d)	Africa	Asia and Other
			(In millions)		
2012					
Property acquisitions (a)					
Unproved	**$ 267**	**$ 179**	**$ 78**	**$ —**	**$ 10**
Proved	**—**	**—**	**—**	**—**	**—**
Exploration (b)	**1,089**	**405**	**89**	**260**	**335**
Production and development capital expenditures (c)	**7,505**	**4,236**	**1,792**	**506**	**971**
2011					
Property acquisitions (a)					
Unproved	$ 1,224	$ 992	$ —	$ —	$ 232
Proved	122	6	116	—	—
Exploration (b)	1,325	525	98	292	410
Production and development capital expenditures (c)	5,645	2,951	1,734	189	771
2010					
Property acquisitions (a, e)					
Unproved	$ 1,887	$ 1,849	$ 38	$ —	$ —
Proved	1,015	443	572	—	—
Exploration (b)	915	185	58	164	508
Production and development capital expenditures (c)	2,654	1,088	850	289	427

(a) Includes wells, equipment and facilities acquired with proved reserves and excludes properties acquired in non-cash property exchanges.

(b) Includes $319 million, $432 million and $64 million of exploration costs incurred for unconventional assets in 2012, 2011 and 2010, respectively.

(c) Includes $715 million, $972 million and $62 million in 2012, 2011 and 2010, respectively, related to the accruals and revisions for asset retirement obligations except obligations acquired in non-cash property exchanges.

(d) Costs incurred in oil and gas producing activities in Norway, excluding non-monetary exchanges, were as follows for the years ended December 31:

	2012	2011	2010
		(In millions)	
Property acquisitions (a)			
Unproved	**$ —**	$ —	$ 14
Proved	**—**	—	572
Exploration	**—**	10	12
*Production and development capital expenditures**	**1,081**	741	469

** Includes accruals and revisions for asset retirement obligations except obligations acquired in non-cash property exchanges.*

(e) In 2010, acquisitions include $652 million, representing the non-cash portion of the purchase price for American Oil & Gas Inc., primarily through the issuance of common stock.

Capitalized Costs Relating to Oil and Gas Producing Activities

	At December 31, 2012	2011
	(In millions)	
Unproved properties	**$ 3,558**	$ 4,064
Proved properties	**4,072**	3,975
Wells, equipment and related facilities	**35,385**	29,239
Total costs	**43,015**	37,278
Less: Reserve for depreciation, depletion, amortization and lease impairment	**15,558**	13,900
Net capitalized costs	**$27,457**	$ 23,378

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, interest expense, gains and losses resulting from foreign exchange transactions 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 18, 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 (b)
			(In millions)		
2012					
Sales and other operating revenues					
Unaffiliated customers	**$ 10,818**	**$ 4,029**	**$ 2,460**	**$ 2,545**	**$ 1,784**
Inter-company	**75**	**75**	**—**	**—**	**—**
Total revenues	**10,893**	**4,104**	**2,460**	**2,545**	**1,784**
Costs and expenses					
Production expenses, including related taxes	**2,752**	**957**	**1,013**	**406**	**376**
Exploration expenses, including dry holes and lease impairment	**1,070**	**426**	**71**	**84**	**489**
General, administrative and other expenses	**314**	**196**	**46**	**17**	**55**
Depreciation, depletion and amortization	**2,853**	**1,406**	**466**	**528**	**453**
Asset impairments	**582**	**432**	**119**	**—**	**31**
Total costs and expenses	**7,571**	**3,417**	**1,715**	**1,035**	**1,404**
Results of operations before income taxes	**3,322**	**687**	**745**	**1,510**	**380**
Provision for income taxes	**1,664**	**269**	**334**	**905**	**156**
Results of operations	**$ 1,658**	**$ 418**	**$ 411**	**$ 605**	**$ 224**
2011					
Sales and other operating revenues					
Unaffiliated customers	$ 9,931	$ 3,255	$ 3,019	$ 2,081	$ 1,576
Inter-company	116	116	—	—	—
Total revenues	10,047	3,371	3,019	2,081	1,576
Costs and expenses					
Production expenses, including related taxes	2,352	660	968	383	341
Exploration expenses, including dry holes and lease impairment	1,195	475	76	231	413
General, administrative and other expenses	313	190	56	17	50
Depreciation, depletion and amortization	2,305	800	588	502	415
Asset impairments	358	16	342	—	—
Total costs and expenses	6,523	2,141	2,030	1,133	1,219
Results of operations before income taxes	3,524	1,230	989	948	357
Provision for income taxes	1,300	473	522	230	75
Results of operations	$ 2,224	$ 757	$ 467	$ 718	$ 282

Table of Contents

For the Years Ended December 31	Total	United States	Europe (a)	Africa	Asia and Other (b)
			(In millions)		
2010					
Sales and other operating revenues					
Unaffiliated customers	$ 8,601	$ 2,310	$ 2,251	$ 2,750	$ 1,290
Inter-company	143	143	—	—	—
Total revenues	8,744	2,453	2,251	2,750	1,290
Costs and expenses					
Production expenses, including related taxes	1,924	489	727	455	253
Exploration expenses, including dry holes and lease impairment	865	364	49	143	309
General, administrative and other expenses	281	161	48	20	52
Depreciation, depletion and amortization	2,222	649	463	772	338
Asset impairments	532	—	—	532	—
Total costs and expenses	5,824	1,663	1,287	1,922	952
Results of operations before income taxes	2,920	790	964	828	338
Provision for income taxes	1,425	305	477	580	63
Results of operations	$ 1,495	$ 485	$ 487	$ 248	$ 275

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

	2012	2011	2010
		(In millions)	
Sales and other operating revenues—Unaffiliated customers	$518	$996	$524
Costs and expenses			
Production expenses, including related taxes	302	290	149
Exploration expenses, including dry holes and lease impairment	—	10	12
General, administrative and other expenses	10	9	9
Depreciation, depletion and amortization	139	232	133
Total costs and expenses	451	541	303
Results of operations before income taxes	67	455	221
Provision for income taxes	(82)	295	154
Results of operations	$149	$160	$ 67

(b) Excludes a 2012 income tax charge of $86 million for a disputed application of an international tax treaty.

Oil and Gas Reserves

The Corporation’s 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. The Corporation’s estimation of net recoverable quantities of liquid hydrocarbons and natural gas is a highly technical process performed by internal teams of geoscience professionals and reservoir engineers. 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. The Corporation’s proved reserves are subject to certain risks and uncertainties, which are discussed in Item 1A, Risk Factors Related to Our Business and Operations of this Form 10-K.

Table of Contents

Internal Controls

The Corporation maintains internal controls over its oil and gas reserve estimation process which are administered by the Corporation's Senior Vice President of E&P Technology and its Chief Financial Officer. Estimates of reserves are prepared by technical staff that 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 below). 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 is Mr. Scott Heck, Senior Vice President of E&P Technology. Mr. Heck 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 includes over 15 years primarily focused on oil and gas subsurface understanding and reserves estimation in both domestic and international areas. The Corporation's upstream technology organization, which Mr. Heck manages, focuses on oil and gas industry subsurface and reservoir engineering technologies and evaluation techniques. Mr. Heck is also 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

The Corporation engaged the consulting firm of DeGolyer and MacNaughton (D&M) to perform an audit of the internally prepared reserve estimates on certain fields aggregating 76% of 2012 year-end reported reserve quantities on a barrel of oil equivalent basis (81% in 2011). 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 January 31, 2013, 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, 2012 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 approximately 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					Natural Gas			
	United States	Europe (g)	Africa	Asia	Total	United States	Europe (g)	Asia and Africa (h)	Total
	(Millions of barrels)					(Millions of mcf)			
Net Proved Developed and Undeveloped Reserves									
At January 1, 2010	249	330	314	74	967 (b)	306	642	1,873	2,821
Revisions of previous estimates (a)	68	14	22	(1)	103	(7)	(9)	(23)	(39)
Extensions, discoveries and other additions	3	19	—	1	23	14	15	1	30
Improved recovery	—	—	—	—	—	—	—	—	—
Purchases of minerals in place	16	150	—	—	166	13	129	—	142
Sales of minerals in place	—	(13)	(25)	(5)	(43)	—	(4)	(89)	(93)
Production (f)	(32)	(34)	(41)	(5)	(112)	(46)	(54)	(163)	(263)
At December 31, 2010	304	466	270	64	1,104 (b)	280	719	1,599	2,598

	Crude Oil, Condensate & Natural Gas Liquids					Natural Gas			
	United States	Europe (g)	Africa	Asia	Total	United States	Europe (g)	Asia and Africa (h)	Total
	(Millions of barrels)					(Millions of mcf)			
Revisions of previous estimates (a)	33	59	(1)	(7)	84	36	7	69	112
Extensions, discoveries and other additions	70	7	5	—	82	85	—	—	85
Improved recovery	—	—	—	—	—	—	—	—	—
Purchases of minerals in place	—	3	—	—	3	1	6	—	7
Sales of minerals in place	—	(7)	—	—	(7)	—	(135)	—	(135)
Production (f)	(34)	(34)	(24)	(5)	(97)	(42)	(34)	(168)	(244)
At December 31, 2011	373	494	250	52	1,169 (b)	360	563	1,500	2,423
Revisions of previous estimates (a)	**32**	**(16)**	**(5)**	**1**	**12**	**10**	**4**	**42**	**56**
Extensions, discoveries and other additions	**108**	**18**	**17**	**1**	**144**	**76**	**1**	**171**	**248**
Improved recovery	**7**	—	—	—	**7**	**4**	—	—	**4**
Purchases of minerals in place	—	—	—	—	—	—	—	—	—
Sales of minerals in place	**(2)**	**(49)**	—	—	**(51)**	—	**(192)**	—	**(192)**
Production (f)	**(45)**	**(31)**	**(28)**	**(6)**	**(110)**	**(50)**	**(19)**	**(175)**	**(244)**
At December 31, 2012	**473**	**416**	**234**	**48**	**1,171 (b)**	**400 (c)**	**357**	**1,538**	**2,295**
Net Proved Developed Reserves (d)									
At January 1, 2010	154	171	241	27	593	205	417	923	1,545
At December 31, 2010	180	210	215	22	627	199	424	692	1,315
At December 31, 2011	190	212	194	25	621	199	273	740	1,212
At December 31, 2012	**280**	**181**	**188**	**27**	**676**	**232**	**190**	**798**	**1,220**
Net Proved Undeveloped Reserves (e)									
At January 1, 2010	95	159	73	47	374	101	225	950	1,276
At December 31, 2010	124	256	55	42	477	81	295	907	1,283
At December 31, 2011	183	282	56	27	548	161	290	760	1,211
At December 31, 2012	**193**	**235**	**46**	**21**	**495**	**168**	**167**	**740**	**1,075**

(a) *Includes the impact of changes in selling prices on the reserve estimates for production sharing contracts with cost recovery provisions. Revisions included reductions to crude oil, condensate and natural gas liquids reserves of 2 million barrels, 11 million barrels and 11 million barrels in 2012, 2011 and 2010, respectively, resulting from higher selling prices. Revisions also included reductions to natural gas reserves of 2 million mcf, 83 million mcf and 62 million mcf in 2012, 2011 and 2010, respectively, resulting from higher selling prices.*

(b) *Includes 8 million barrels in 2012, 10 million barrels in 2011 and 15 million barrels in 2010 of crude oil reserves relating to a noncontrolling interest owner of a corporate joint venture.*

(c) *Excludes approximately 290 million mcf of carbon dioxide gas for sale or use in company operations.*

(d) *Natural gas liquids net proved developed reserves were 76 million barrels, 56 million barrels and 54 million barrels at December 31, 2012, 2011 and 2010, respectively, and 41 million barrels at January 1, 2010. Natural gas liquids net proved developed reserves in the United States were 82%, 74% and 72% at December 31, 2012, 2011 and 2010, respectively. Natural gas liquids net proved developed reserves in Norway were 10%, 16% and 17% at December 31, 2012, 2011 and 2010, respectively.*

(e) *Natural gas liquids net proved undeveloped reserves were 60 million barrels, 57 million barrels and 48 million barrels at December 31, 2012, 2011 and 2010, respectively, and 30 million barrels at January 1, 2010. Natural gas liquids net proved undeveloped reserves in the United States were 72%, 67% and 58% at December 31, 2012, 2011 and 2010, respectively. Natural gas liquids net proved undeveloped reserves in Norway were 25%, 28% and 28% at December 31, 2012, 2011 and 2010, respectively.*

(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		
	2012	2011	2010	2012	2011	2010
	(Millions of barrels)			(Millions of mcf)		
At January 1	**293**	264	136	**388**	404	287
Revisions of previous estimates	**—**	40	(16)	**1**	(4)	(1)
Purchases of minerals in place	**—**	—	150	**—**	—	130
Sales of minerals in place	**(5)**	(3)	—	**(165)**	—	—
Production	**(4)**	(8)	(6)	**(5)**	(12)	(12)
At December 31	**284**	293	264	**219**	388	404
Net Proved Developed Reserves at December 31	**102**	108	97	**73**	137	157
Net Proved Undeveloped Reserves at December 31	**182**	185	167	**146**	251	247

(h) *Natural gas reserves in Africa were 142 million mcf in 2012, 71 million mcf in 2011 and 63 million mcf in 2010.*

Proved undeveloped reserves

The December 31, 2012 oil and gas reserve estimates disclosed above include 495 million barrels of liquid hydrocarbons and 1,075 million mcf of natural gas, or an aggregate of 674 million barrels of oil equivalent (boe), classified as proved undeveloped reserves. Overall volumes of proved undeveloped reserves decreased by 76 million boe compared with year-end 2011. Additions and revisions in proved undeveloped reserves from existing fields amounted to 37 million boe, primarily in the United States, Indonesia and Russia. These increases resulted from ongoing technical assessments, performance evaluations and development activities. In 2012, 55 million boe were converted from proved undeveloped reserves to proved developed reserves resulting from continuing development activity and new wells principally in North Dakota, Texas and the Gulf of Mexico in the United States, Libya, Indonesia, Equatorial Guinea and at the Joint Development Area of Malaysia/Thailand (JDA). The Corporation estimates that capital expenditures of $734 million were incurred to convert proved undeveloped reserves to proved developed reserves during 2012. Dispositions of assets in 2012 further reduced proved undeveloped reserves by 59 million boe.

The Corporation is 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 103 million boe or 7% of total 2012 proved reserves. Most of the proved undeveloped reserves in excess of five years relate to five offshore producing assets. As discussed below, natural gas projects at the JDA, Natuna and Pangkah are being developed in phases to meet long-term natural gas sales contracts and oil and gas projects at the Valhall Field in Norway and the Azeri-Chirag-Guneshli fields in Azerbaijan are being developed in phases. A summary of the development status of each of the five projects follows:

- JDA — This natural gas project in the Gulf of Thailand currently has a central processing platform and nine wellhead platforms. Two additional wellhead platforms are currently under construction and the twelfth is in the process of being sanctioned. In addition, a major investment in compression equipment was sanctioned in 2012.
- Natuna A — This natural gas project offshore Sumatra, Indonesia currently has two wellhead platforms, two central processing facilities and a floating storage and offloading vessel. Additional wellhead platforms and subsea well tie-backs are planned to satisfy gas sales contracts.
- Pangkah — This natural gas and oil project offshore Java, Indonesia currently has a central processing platform, accommodation and utility platform, two producing offshore wellhead platforms and onshore production facilities. Further development drilling is planned.
- Valhall — The multi-year Valhall Redevelopment project (VRD) was completed in early 2013. The project included the installation of a new production, utilities and accommodation platform, and expansion of gross production capacity to 120,000 barrels of liquids per day and 143,000 mcf of natural gas per day. In July 2012, the field was shut-in to complete the installation and commissioning of the new facilities and production resumed in January 2013. The operator plans a multi-year development drilling program commencing in 2013.
- Azeri-Chirag-Guneshli — This oil project offshore Azerbaijan in the Caspian Sea has seven operational platforms that have been completed over multiple phases of development. This asset is classified as held for sale at December 31, 2012.

Table of Contents

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, 2012 are presented separately below, as well as volumes produced and received during 2012, 2011 and 2010 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*									
At December 31, 2010	—	—	108	57	165	—	—	1,316	1,316
At December 31, 2011	—	—	89	46	135	—	—	1,230	1,230
At December 31, 2012	**—**	**—**	**76**	**40**	**116**	**—**	**—**	**1,183**	**1,183**
Production									
2010	—	—	33	4	37	—	—	130	130
2011	—	—	23	4	27	—	—	136	136
2012	**—**	**—**	**20**	**6**	**26**	**—**	**—**	**137**	**137**

** Includes natural gas liquids of 5 million barrels in 2012, 5 million barrels in 2011 and 7 million barrels in 2010.*

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

Future net cash flows are calculated by applying prescribed oil and gas selling prices used in determining year-end reserve estimates (adjusted for price changes provided by contractual arrangements) to estimated future production of proved oil and gas reserves, less estimated future development and production costs, which are based on year-end costs and existing economic assumptions. Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the pre-tax net cash flows relating to the Corporation's proved oil and gas reserves. Future net cash flows are discounted at the prescribed rate of 10%. The discounted future net cash flow estimates do not include exploration expenses, interest expense or corporate general and administrative expenses. The selling prices of crude oil and natural gas are highly volatile. The prices which are required to be used for the discounted future net cash flows do not include the effects of hedges and may not be representative of future selling prices. The future net cash flow estimates could be materially different if other assumptions were used.

Table of Contents

At December 31	Total	United States	Europe*	Africa	Asia
			(In millions)		
2012					
Future revenues	**$ 126,603**	**$ 39,900**	**$ 44,387**	**$ 27,162**	**$ 15,154**
Less:					
Future production costs	**32,529**	**12,603**	**13,277**	**3,547**	**3,102**
Future development costs	**17,363**	**6,465**	**6,648**	**1,623**	**2,627**
Future income tax expenses	**44,201**	**7,686**	**16,273**	**17,510**	**2,732**
	94,093	**26,754**	**36,198**	**22,680**	**8,461**
Future net cash flows	**32,510**	**13,146**	**8,189**	**4,482**	**6,693**
Less: Discount at 10% annual rate	**11,951**	**5,906**	**2,683**	**1,109**	**2,253**
Standardized measure of discounted future net cash flows	**$ 20,559**	**$ 7,240**	**$ 5,506**	**$ 3,373**	**$ 4,440**
2011					
Future revenues	$126,874	$ 33,225	$50,876	$27,299	$ 15,474
Less:					
Future production costs	31,517	9,220	16,020	3,455	2,822
Future development costs	17,858	5,854	7,751	1,761	2,492
Future income tax expenses	43,008	7,022	16,368	16,933	2,685
	92,383	22,096	40,139	22,149	7,999
Future net cash flows	34,491	11,129	10,737	5,150	7,475
Less: Discount at 10% annual rate	14,753	6,190	4,599	1,488	2,476
Standardized measure of discounted future net cash flows	$ 19,738	$ 4,939	$ 6,138	$ 3,662	$ 4,999
2010					
Future revenues	$ 91,336	$21,112	$36,157	$ 21,150	$12,917
Less:					
Future production costs	21,635	6,155	9,536	3,332	2,612
Future development costs	13,554	3,178	6,534	1,269	2,573
Future income tax expenses	30,250	4,423	11,745	12,173	1,909
	65,439	13,756	27,815	16,774	7,094
Future net cash flows	25,897	7,356	8,342	4,376	5,823
Less: Discount at 10% annual rate	10,195	3,764	3,361	1,028	2,042
Standardized measure of discounted future net cash flows	$ 15,702	$ 3,592	$ 4,981	$ 3,348	$ 3,781

Table of Contents

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

	2012	2011	2010
		(In millions)	
Future revenues	**$33,974**	$34,495	$23,115
Less:			
Future production costs	**9,734**	10,596	4,399
Future development costs	**4,507**	4,270	3,426
Future income tax expenses	**14,976**	13,247	9,908
	29,217	28,113	17,733
Future net cash flows	**4,757**	6,382	5,382
Less: Discount at 10% annual rate	**1,587**	2,755	2,156
Standardized measure of discounted future net cash flows	**$ 3,170**	$ 3,627	$ 3,226

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

For the Years Ended December 31	2012	2011	2010
		(In millions)	
Standardized measure of discounted future net cash flows at January 1	**$19,738**	$15,702	$ 11,401
Changes during the year			
Sales and transfers of oil and gas produced during the year, net of production costs	**(8,141)**	(7,695)	(6,820)
Development costs incurred during year	**6,790**	4,673	2,592
Net changes in prices and production costs applicable to future production	**1,678**	9,233	7,970
Net change in estimated future development costs	**(2,181)**	(1,963)	(1,678)
Extensions and discoveries (including improved recovery) of oil and gas reserves, less related costs	**3,612**	1,040	356
Revisions of previous oil and gas reserve estimates	**1,890**	2,587	1,885
Net purchases (sales) of minerals in place, before income taxes	**(1,856)**	(398)	3,193
Accretion of discount	**4,032**	3,096	2,011
Net change in income taxes	**(1,906)**	(5,234)	(5,848)
Revision in rate or timing of future production and other changes	**(3,097)**	(1,303)	640
Total	**821**	4,036	4,301
Standardized measure of discounted future net cash flows at December 31	**$ 20,559**	$19,738	$15,702

Table of Contents

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
QUARTERLY FINANCIAL DATA (UNAUDITED)

Following are quarterly results of operations:

	Sales and Other Operating Revenues	Gross Profit (a)	Net Income (Loss) Attributable to Hess Corporation	Net Income (Loss) Per Share Attributable to Hess Corporation Basic	Diluted
	(In millions, except per share amounts)				
2012					
First	**$ 9,682**	**$ 1,357**	**$ 545 (b)**	**$ 1.61**	**$ 1.60**
Second	**9,304**	**1,524**	**549 (c)**	**1.62**	**1.61**
Third	**9,194**	**1,207**	**557 (d)**	**1.65**	**1.64**
Fourth	**9,511**	**1,164**	**374 (e)**	**1.10**	**1.10**
2011					
First	$ 10,215	$ 1,761	$ 929 (f)	$ 2.77	$ 2.74
Second	9,853	1,536	607	1.80	1.78
Third	8,665	622	298 (g)	0.89	0.88
Fourth	9,733	1,417	(131)(h)	(0.39)	(0.39)

(a) Gross profit represents Sales and other operating revenues, less Cost of products sold, Production expenses, Marketing expenses, Other operating expenses, Depreciation, depletion and amortization and Asset impairments.

(b) Includes an after-tax gain of $36 million related to an asset sale.

(c) Includes an after-tax charge of $36 million related to an asset impairment.

(d) Includes an after-tax gain of $349 million related to an asset sale, partially offset by after-tax charges of $116 million for asset impairments and $56 million to write off the Corporation's exploration assets in Peru and an income tax charge of $115 million to reflect a change in the United Kingdom supplementary income tax rate applicable to deductions for dismantlement expenditures.

(e) Includes an after-tax charge of $192 million for an asset impairment, an income tax charge of $86 million and after-tax charges of $33 million for asset impairments and other charges, partially offset by an after-tax gain of $172 million related to an asset sale and after-tax income of $104 million from the partial liquidation of LIFO inventories.

(f) Includes an after-tax gain of $310 million related to asset sales.

(g) Includes an after-tax charge of $140 million related to asset impairments and an income tax charge of $29 million for an increase in the United Kingdom supplementary tax rate, partially offset by after-tax gains of $103 million related to asset sales.

(h) Includes an after-tax charge of $525 million related to the shutdown of the HOVENSA L.L.C. (HOVENSA) refinery in St. Croix, U.S. Virgin Islands.

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, 2012, 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, 2012.

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, 2012 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 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 2013 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 2013 annual meeting of stockholders.

Executive Officers of the Registrant

The following table presents information as of February 1, 2013 regarding executive officers of the Registrant:

Name	Age	Office Held*	Year Individual Became an Executive Officer
John B. Hess	58	Chairman of the Board, Chief Executive Officer and Director	1983
Gregory P. Hill	51	Executive Vice President and President of Worldwide Exploration and Production and Director	2009
F. Borden Walker	59	Executive Vice President and President of Marketing and Refining and Director	1996
Timothy B. Goodell	55	Senior Vice President and General Counsel	2009
Lawrence H. Ornstein	61	Senior Vice President	1995
John P. Rielly	50	Senior Vice President and Chief Financial Officer	2002
John J. Scelfo	55	Senior Vice President	2004
Mykel J. Ziolo	60	Senior Vice President	2009
Robert M. Biglin	48	Vice President and Treasurer	2010

** 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 2, 2012.*

Except for Messrs. Hill and Goodell, each of the above officers has been employed by the Registrant or its subsidiaries in various managerial and executive capacities for more than five years. Prior to joining the Corporation, Mr. Hill served in senior executive positions in exploration and production operations at Royal Dutch Shell and its subsidiaries, where he was employed for 25 years. Before joining the Corporation in 2009, Mr. Goodell was a partner in the law firm of White & Case LLP.

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 2013 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 2013 annual meeting of stockholders.

See Equity Compensation Plans in Item 5 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 2013 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 2013 annual meeting of stockholders.

Table of Contents

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

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)	By-laws of Registrant incorporated by reference to Exhibit 3(1) of Form 8-K of Registrant dated February 2, 2011.
4(1)	Five-Year Credit Agreement dated as of April 14, 2011, 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 dated April 14, 2011.
4(2)	Indenture dated as of October 1, 1999 between Registrant and The Chase Manhattan Bank, as Trustee, incorporated by reference to Exhibit 4(1) of Form 10-Q of Registrant for the three months ended September 30, 1999.
4(3)	First Supplemental Indenture dated as of October 1, 1999 between Registrant and The Chase Manhattan Bank, as Trustee, relating to Registrant's $7^{3}/_{8}$% Notes due 2009 and $7^{7}/_{8}$% Notes due 2029, incorporated by reference to Exhibit 4(2) to Form 10-Q of Registrant for the three months ended September 30, 1999.
4(4)	Prospectus Supplement dated August 8, 2001 to Prospectus dated July 27, 2001 relating to Registrant's 5.30% Notes due 2004, 5.90% Notes due 2006, 6.65% Notes due 2011 and 7.30% Notes due 2031, incorporated by reference to Registrant's prospectus filed pursuant to Rule 424(b)(2) under the Securities Act of 1933 on August 9, 2001.
4(5)	Prospectus Supplement dated February 28, 2002 to Prospectus dated July 27, 2001 relating to Registrant's 7.125% Notes due 2033, incorporated by reference to Registrant's prospectus filed pursuant to Rule 424(b)(2) under the Securities Act of 1933 on March 1, 2002.
4(6)	Indenture dated as of March 1, 2006 between Registrant and The Bank of New York Mellon as successor to JP Morgan Chase, as Trustee, including form of Note. Incorporated by reference to Exhibit 4 to Registrant's Form S-3ASR filed with the Securities and Exchange Commission on March 1, 2006.
4(7)	Form of 2014 Note issued pursuant to Indenture, dated as of March 1, 2006, among Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase as Trustee. Incorporated by reference to Exhibit 4(1) to Registrant's Form 8-K filed with the Securities and Exchange Commission on February 4, 2009.
4(8)	Form of 2019 Note issued pursuant to Indenture, dated as of March 1, 2006, among Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase, as Trustee. Incorporated by reference to Exhibit 4(2) to Registrant's Form 8-K filed with the Securities and Exchange Commission on February 4, 2009.
4(9)	Form of 6.00% Note, incorporated by reference to Exhibit 4(1) to the Form 8-K of Registrant filed on December 15, 2009.
4(10)	Form of 5.60% Note incorporated by reference to Exhibit 4(1) to the Form 8-K of Registrant filed on August 12, 2010. 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 Commission a copy of any instruments defining the rights of holders of long-term debt of Registrant and its subsidiaries upon request.
10(1)	Extension and Amendment Agreement between the Government of the Virgin Islands and Hess Oil Virgin Islands Corp. incorporated by reference to Exhibit 10(4) of Form 10-Q of Registrant for the three months ended June 30, 1981.
10(2)	Restated Second Extension and Amendment Agreement dated July 27, 1990 between Hess Oil Virgin Islands Corp. and the Government of the Virgin Islands incorporated by reference to Exhibit 19 of Form 10-Q of Registrant for the three months ended September 30, 1990.

10(3)	Technical Clarifying Amendment dated as of November 17, 1993 to Restated Second Extension and Amendment Agreement between the Government of the Virgin Islands and Hess Oil Virgin Islands Corp. incorporated by reference to Exhibit 10(3) of Form 10-K of Registrant for the fiscal year ended December 31, 1993.
10(4)	Third Extension and Amendment Agreement dated April 15, 1998 and effective October 30, 1998 among Hess Oil Virgin Islands Corp., PDVSA V.I., Inc., HOVENSA L.L.C. and the Government of the Virgin Islands incorporated by reference to Exhibit 10(4) of Form 10-K of Registrant for the fiscal year ended December 31, 1998.
10(5)*	Incentive Cash Bonus Plan description incorporated by reference to Item 5.02 of Form 8-K of Registrant filed on March 13, 2012.
10(6)*	Financial Counseling Program description incorporated by reference to Exhibit 10(6) of Form 10-K of Registrant for fiscal year ended December 31, 2004.
10(7)*	Hess Corporation Savings and Stock Bonus Plan incorporated by reference to Exhibit 10(7) of Form 10-K of Registrant for fiscal year ended December 31, 2006.
10(8)*	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 the Registrant dated March 25, 2011.
10(9)*	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(10)*	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 fiscal year ended December 31, 2006.
10(11)*	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(12)*	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 fiscal year ended December 31, 2004.
10(13)*	2008 Long-term Incentive Plan, incorporated by reference to Annex B to Registrant's definitive proxy statement filed on March 27, 2008.
10(14)*	First Amendment dated March 3, 2010 and approved May 5, 2010 to Registrant's 2008 Long-term Incentive Plan, incorporated by reference to Annex B of Registrant's definitive proxy statement dated March 25, 2010.
10(15)*	Forms of Awards under Registrant's 2008 Long-term Incentive Plan incorporated by reference to Exhibit 10(14) of Registrant's Form 10-K for the fiscal year ended December 31, 2009.
10(16)*	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(17)*	Modified Form of Restricted Stock Award Agreement under Registrant's 2008 Long-term Incentive Plan incorporated by reference to Exhibit 10(3) of Form 8-K of Registrant filed on March 13, 2012.
10(18)*	Second Amendment dated March 23, 2012 and approved May 2, 2012 to Registrant's 2008 Long-term Incentive Plan, incorporated by reference to Annex A of Registrant's definitive proxy statement dated March 23, 2012.
10(19)*	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(20)*	Amended and Restated Change of Control Termination Benefits Agreement dated as of May 29, 2009 between Registrant and F. Borden Walker, 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(21)*	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 Registrant's Form 10-K 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 those referred to in Exhibit 10(17)).
10(22)*	Letter Agreement dated March 18, 2002 between Registrant and F. Borden Walker relating to Mr. Walker's participation in the Hess Corporation Pension Restoration Plan incorporated by reference to Exhibit 10(16) of Form 10-K of Registrant for the fiscal year ended December 31, 2001.

10(23)*	Agreement between Registrant and Gregory P. Hill relating to his compensation and other terms of employment, incorporated by reference to Item 5.02 of Form 8-K of Registrant filed January 7, 2009.
10(24)*	Agreement between Registrant and Timothy B. Goodell relating to his 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(25)*	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(26)	Asset Purchase and Contribution Agreement dated as of October 26, 1998, among PDVSA V.I., Inc., Hess Oil Virgin Islands Corp. and HOVENSA L.L.C. (including Glossary of definitions) incorporated by reference to Exhibit 2.1 of Form 8-K of Registrant filed on November 13, 1998.
10(27)	Amended and Restated Limited Liability Company Agreement of HOVENSA L.L.C. dated as of October 30, 1998 incorporated by reference to Exhibit 10.1 of Form 8-K of Registrant filed on November 13, 1998.
21	Subsidiaries of Registrant.
23(1)	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm, dated February 28, 2013, to the incorporation by reference in Registrant's Registration Statements (Form S-3 No. 333-179744, and Form S-8 Nos. 333-43569, 333-94851, 333-115844, 333-150992, 333-167076 and 333-181704), of its reports relating to Registrant's financial statements.
23(2)	Consent of DeGolyer and MacNaughton dated February 28, 2013.
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 January 31, 2013, on proved reserves audit as of December 31, 2012 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.*

(b) Reports on Form 8-K

During the three months ended December 31, 2012, Registrant filed or furnished the following report on Form 8-K:

1. Filing dated November 2, 2012 reporting under Items 2.02 and 9.01, a news release dated November 2, 2012 reporting results for the third quarter of 2012 and furnishing under Items 7.01 and 9.01 the prepared remarks of John B. Hess, Chairman of the Board of Directors and Chief Executive Officer of Hess Corporation, at a public conference call held November 2, 2012.

Table of Contents

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 28th day of February 2013.

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 **John B. Hess**	Director, Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	February 28, 2013
/s/ SAMUEL W. BODMAN **Samuel W. Bodman**	Director	February 28, 2013
/s/ NICHOLAS F. BRADY **Nicholas F. Brady**	Director	February 28, 2013
/s/ GREGORY P. HILL **Gregory P. Hill**	Director	February 28, 2013
/s/ EDITH E. HOLIDAY **Edith E. Holiday**	Director	February 28, 2013
/s/ THOMAS H. KEAN **Thomas H. Kean**	Director	February 28, 2013
/s/ RISA LAVIZZO-MOUREY **Risa Lavizzo-Mourey**	Director	February 28, 2013
/s/ CRAIG G. MATTHEWS **Craig G. Matthews**	Director	February 28, 2013
/s/ JOHN H. MULLIN **John H. Mullin**	Director	February 28, 2013
/s/ SAMUEL A. NUNN **Samuel A. Nunn**	Director	February 28, 2013
/s/ FRANK A. OLSON **Frank A. Olson**	Director	February 28, 2013
/s/ JOHN P. RIELLY **John P. Rielly**	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 28, 2013
/s/ ERNST H. VON METZSCH **Ernst H. von Metzsch**	Director	February 28, 2013
/s/ F. BORDEN WALKER **F. Borden Walker**	Director	February 28, 2013
/s/ ROBERT N. WILSON **Robert N. Wilson**	Director	February 28, 2013

Table of Contents

Schedule II

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

For the Years Ended December 31, 2012, 2011 and 2010

Description	Balance January 1	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions from Reserves	Balance December 31
			(In millions)		
2012					
Losses on receivables	**$ 55**	**$ —**	**$ —**	**$ 21**	**$ 34**
Deferred income tax valuation	**$ 1,071**	**$ 248**	**$ —**	**$ 37**	**$ 1,282**
2011					
Losses on receivables	$ 58	$ 4	$ 1	$ 8	$ 55
Deferred income tax valuation	$ 444	$ 648	$ —	$ 21	$ 1,071
2010					
Losses on receivables	$ 54	$ 9	$ 1	$ 6	$ 58
Deferred income tax valuation	$ 500	$ 135	$ —	$ 191	$ 444

Table of Contents

Report of Independent Auditors

The Members
HOVENSA L.L.C.

We have audited the accompanying balance sheet of HOVENSA L.L.C. ("the Company") as of December 31, 2011, and the related statements of operations, comprehensive loss and (accumulated deficit) retained earnings, and cash flows for each of the two years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the 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. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and 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 financial position of HOVENSA L.L.C. at December 31, 2011, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2011 in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young, LLP
February 27, 2012
New York, New York

Table of Contents

HOVENSA L.L.C.

BALANCE SHEETS
(Dollars in thousands)

	December 31, 2012 (Unaudited)	December 31, 2011 (Audited)
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 336,570**	$ 42,275
Debt service fund	—	11,361
Accounts receivable:		
Members and affiliates	**268**	36,694
Trade (less allowance in 2012 of $6,859 and 2011 of $52,416)	**8,783**	104,776
Other	**851**	228
Inventories	**68,230**	159,594
Deposits and prepaid expenses	**1,485**	15,707
Total current assets	**416,187**	370,635
PROPERTY, PLANT AND EQUIPMENT		
Land	—	19,315
Refinery facilities	—	3,012,619
Other	—	108,307
Construction in progress	—	29,722
Total — at cost	—	3,169,963
Less: Accumulated depreciation	—	(3,169,963)
Property, plant and equipment — net	—	—
OTHER ASSETS	**119**	10,374
TOTAL ASSETS	**$ 416,306**	$ 381,009
LIABILITIES AND MEMBERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable:		
Members and affiliates	**$ —**	$ 423,706
Trade	**19,117**	346,917
Tax-exempt revenue bonds	—	355,683
Accrued liabilities	**190,158**	76,480
Interest and taxes payable	**64,843**	1,459
Payable to members for financial support	**1,622,000**	654,000
Total current liabilities	**1,896,118**	1,858,245
OTHER LIABILITIES	**102,222**	115,223
Total liabilities	**1,998,340**	1,973,468
MEMBERS' EQUITY		
Members' initial investment	**1,343,429**	1,343,429
Accumulated deficit	**(2,885,218)**	(2,898,232)
Accumulated other comprehensive loss	**(40,245)**	(37,656)
Total members' equity	**(1,582,034)**	(1,592,459)
TOTAL LIABILITIES AND MEMBERS' EQUITY	**$ 416,306**	$ 381,009

See accompanying notes to financial statements.

Table of Contents

HOVENSA L.L.C.

STATEMENTS OF OPERATIONS, COMPREHENSIVE INCOME (LOSS) AND (ACCUMULATED DEFICIT) RETAINED EARNINGS
(Dollars in thousands)

	Years Ended December 31,		
	2012 (Unaudited)	2011 (Audited)	2010 (Audited)
SALES	**$ 1,633,357**	$ 13,126,326	$ 12,258,297
OPERATING EXPENSES			
Product costs	**1,073,019**	12,803,408	11,926,310
Operating expenses	**324,794**	554,516	586,336
Depreciation and amortization	**—**	128,403	142,503
Asset impairments and shutdown related charges	**152,759**	2,072,600	—
Total operating expenses	**1,550,572**	15,558,927	12,655,149
OPERATING INCOME (LOSS)	**82,785**	(2,432,601)	(396,852)
OTHER NON-OPERATING INCOME (EXPENSE)			
Interest expense	**(82,419)**	(38,689)	(25,904)
Other income (expense), net	**12,648**	(15,962)	(15,173)
NET INCOME (LOSS)	**$ 13,014**	$ (2,487,252)	$ (437,929)
COMPONENTS OF COMPREHENSIVE INCOME (LOSS)			
Net income (loss)	**$ 13,014**	$ (2,487,252)	$ (437,929)
Other comprehensive income (loss):			
Change in retirement plan liabilities	**(2,589)**	9,898	(1,789)
COMPREHENSIVE INCOME (LOSS)	**$ 10,425**	$ (2,477,354)	$ (439,718)
(ACCUMULATED DEFICIT) RETAINED EARNINGS			
Opening balance	**$(2,898,232)**	$ (410,980)	$ 26,949
Net income (loss)	**13,014**	(2,487,252)	(437,929)
CLOSING BALANCE	**$(2,885,218)**	$ (2,898,232)	$ (410,980)

See accompanying notes to financial statements.

Table of Contents

HOVENSA L.L.C.

STATEMENTS OF CASH FLOWS
(Dollars in thousands)

	Years Ended December 31,		
	2012 (Unaudited)	2011 (Audited)	2010 (Audited)
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	**$ 13,014**	$(2,487,252)	$(437,929)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation and amortization	—	128,403	142,503
Asset impairments and shutdown related charges	**152,759**	2,072,600	—
(Increase) decrease in accounts receivable	**177,445**	181,227	(104,173)
(Increase) decrease in inventories	**80,724**	65,698	16,043
(Increase) decrease in deposits and prepaid expenses	**12,353**	(510)	(55)
(Increase) decrease in other assets	**10,255**	16,419	26,695
Increase (decrease) in accounts payable and accrued liabilities	**(812,828)**	(218,068)	47,343
Increase (decrease) in interest and taxes payable	**63,384**	(509)	143
Increase (decrease) in other liabilities	**(26,489)**	(25,473)	(2,798)
Net cash used in operating activities	**(329,383)**	(267,465)	(312,228)
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	—	(39,373)	(70,206)
Net cash used in investing activities	—	(39,373)	(70,206)
CASH FLOWS FROM FINANCING ACTIVITIES			
(Increase) decrease in debt service fund	**11,361**	(11)	(17)
Increase (decrease) in long-term debt, net	**(355,683)**	(350,000)	350,000
Increase in payable to members for financial support	**968,000**	654,000	—
Net cash provided by financing activities	**623,678**	303,989	349,983
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**294,295**	(2,849)	(32,451)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**42,275**	45,124	77,575
CASH AND CASH EQUIVALENTS AT END OF YEAR	**$ 336,570**	$ 42,275	$ 45,124

See accompanying notes to financial statements.

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS
(Dollars in thousands)

1. Basis of Financial Statements and Significant Accounting Policies

Nature of Business

Background: HOVENSA L.L.C. (the "Company" or "HOVENSA") was formed as a 50/50 joint venture between subsidiaries of Petroleos de Venezuela, SA. ("PDVSA") and Hess Corporation ("Hess"), to own and operate the Company's refinery located in St. Croix, United States (U.S.) Virgin Islands. The Company's members are PDVSA V.I., Inc., a subsidiary of PDVSA, and Hess Oil Virgin Islands Corp. ("HOVIC"), a subsidiary of Hess. Through January 2012, the Company purchased crude oil from PDVSA, Hess and third parties, and manufactured and sold petroleum products primarily to PDVSA and Hess.

HOVENSA operates under a Concession Agreement with the Government of the U.S. Virgin Islands. The original Concession Agreement was entered into on September 1, 1965 and the Third Amendment to the Concession Agreement is due to expire on August 1, 2022. The Concession Agreement can be extended with Virgin Islands government approval which has occurred on two previous occasions.

Shutdown of Refinery: In December 2011, the Company's members agreed to shut down refining operations effective January 18, 2012. As a result of this decision, the Company recorded non-cash charges totaling $2,072,600 in December 2011 to fully impair its property, plant and equipment and recognize certain other expenses related to the shutdown decision. Following the refinery shutdown, the Company redeemed its outstanding debt, liquidated a majority of its inventory and settled a portion of its liabilities. In 2012, additional shutdown related charges totaling $152,759 were recorded, primarily for the estimated legal obligations for hydrocarbon removal and tank cleaning costs.

During 2012 and continuing into 2013, HOVENSA and the Government of the Virgin Islands engaged in discussions pertaining to HOVENSA's plan to run the facility as an oil storage terminal while Hess and PDVSA pursue a sale of HOVENSA.

Basis of Presentation and Going Concern

The accompanying financial statements of HOVENSA have been prepared in conformity with United States generally accepted accounting principles ("U.S. GAAP"). These financial statements have been prepared assuming HOVENSA will continue as a going concern. As further explained in Notes 2 and 3 below, the Company fully impaired its property, plant and equipment and recorded certain refinery shutdown costs at December 31, 2011. Additional refinery shutdown costs were recorded in 2012. The Company received financial support from the members in 2012 to fund expenditures for the refinery shutdown and conversion to an oil storage terminal. The Company believes that it has adequate funding for 2013 activities.

Use of Estimates

In preparing financial statements in conformity with U.S. GAAP, management makes estimates and assumptions that affect the reported amounts of assets and liabilities in the balance sheet and revenues and expenses in the statement of operations. Actual results could differ from those estimates. Among the estimates made by management are asset impairments, refinery shutdown costs, inventory and other asset valuations, legal and environmental obligations and pension liabilities.

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS – (Continued)
(Dollars in Thousands)

Revenue Recognition

The Company recognizes revenues from the sale of petroleum products when title passes to the customer, which generally occurs when products are shipped or delivered in accordance with the terms of the respective sales agreements.

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.

Debt Service Fund

The debt service fund is cash held by a trustee representing six months of interest and fees payable on the Company’s outstanding tax-exempt revenue bonds.

Inventories

Inventories of crude oil and refined products used in refining operations are valued at the lower of last-in, first-out (“LIFO”) cost or market. Other inventories, including refined products purchased for resale or used in operations, as well as materials and supplies are valued at the lower of average cost or market.

Depreciation

Depreciation of refinery facilities through December 31, 2011 was determined principally on the units-of-production method based on estimated production volumes. Depreciation of all other equipment was determined on the straight-line method based on estimated useful lives.

Maintenance and Repairs

Maintenance and repairs are expensed as incurred.

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. The impairment recognized is the amount by which the carrying amount exceeds the estimated fair market value of the assets.

Asset Retirement Obligations

Asset retirement obligations must be recorded at fair value in the period in which it is determined that a legal obligation exists and a reasonable estimate of the fair value of the liability can be made.

Environmental Expenditures

Liabilities for future remediation costs are recorded when environmental assessments or remedial efforts are probable and the costs can be reasonably estimated. Other than for assessments, the timing and magnitude of these accruals generally are based on the completion of investigations or other studies or a commitment to a formal plan of action. Environmental liabilities are based on best estimates of probable undiscounted future costs using currently available technology and applying current regulations. Such accruals are adjusted as further information develops or circumstances change. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable.

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS – (Continued)
(Dollars in Thousands)

Income Taxes

The Company is a limited liability company and, as a result, income taxes are the responsibility of the members. Accordingly, no effect of income tax has been recognized in the accompanying financial statements.

Retirement Plans

The Company recognizes on its balance sheet the underfunded status of its defined benefit retirement plans measured as the difference between the fair value of plan assets and the benefit obligations. The benefit obligation is the projected benefit obligation in the case of the non-contributory defined benefit pension plan and the projected post-retirement benefit obligation for the post-retirement medical plan. The Company recognizes the net changes in the plan assets and benefit obligations of its defined benefit retirement plans in the year in which such changes occur.

Prior service costs and 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.

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 and rate of future increases in compensation levels. These assumptions represent estimates made by the Company, some of which can be affected by external factors.

Subsequent Events

Subsequent events have been evaluated through February 28, 2013.

2. Asset Impairment and Refinery Shutdown Related Charges

On January 18, 2012, HOVENSA announced the decision to shut down its refinery operations after experiencing substantial operating losses due to global economic conditions and competitive disadvantages versus other refiners. Such losses were incurred despite efforts to improve operating performance by reducing refining capacity to 350,000 barrels per day from 500,000 barrels per day in the first half of 2011. Operating losses were also projected to continue. The Company prepared an impairment analysis as of December 31, 2011, which indicated that undiscounted future cash flows would not recover the carrying value of its assets. As a result, the Company recorded an impairment charge of $1,900,349 representing the difference between the carrying value and the estimated fair market value of property, plant and equipment at December 31, 2011. Estimated fair value was determined based on discounted future cash flows (a Level 3 fair value measure). In addition, the Company recorded other charges for obligations incurred in 2011 related to the decision to shut down the refinery totaling $172,251, including recognition of legally required employee and contractor severance costs and a reduction in carrying value of warehouse inventory and other assets.

During 2012, the Company recorded an additional $152,759 primarily for estimated obligations incurred due to hydrocarbon removal and tank cleaning costs, which became legal obligations upon shutdown of the refinery.

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS – (Continued)
(Dollars in Thousands)

3. Future Refinery Shutdown Expenditures

The Company is expected to incur additional refinery shutdown costs in excess of amounts that can be accrued at December 31, 2012 and 2011 under US GAAP, including costs related to the preservation of refinery process equipment, enhanced employee and contractor severance and benefits, estimated losses on long-term contracts and other costs. The Company estimated that after liquidation of current assets and liabilities approximately $900,000 would be required to settle all obligations at December 31, 2011. Approximately $735,000 was paid in 2012, with no material change in the total estimated obligations.

4. Related Party Transactions

During 2012 and 2011, HOVENSA received financial support from its members primarily by delaying the normal timing of payments to PDVSA for crude oil purchases, as well as accelerating payments from Hess for refined product sales. At December 31, 2012 and 2011, interest bearing financial support provided by both members in the aggregate of $1,622,000 and $654,000, respectively, is recorded as a current liability in the balance sheet. Interest expense incurred of $82,419 in 2012 relates primarily to the payable to members for financial support.

The Company has long-term crude oil supply agreements with Petroleum Marketing International ("Petromar") a subsidiary of PDVSA, under which Petromar agrees to sell to HOVENSA a monthly average of 155,000 barrels per day of Mesa crude oil and 115,000 barrels per day of Merey crude oil. The Company also has a product sales agreement with Hess and Petromar that requires Hess and Petromar each to purchase after any sales of refined products by HOVENSA to third parties, 50% of HOVENSA's gasoline, distillate, residual fuel and other products at market prices. Purchases and sales under these agreements ceased on April 1, 2012 following the shutdown of refining operations.

A summary of all material transactions between the Company, its members and affiliates follows:

	2012 (Unaudited)	2011 (Audited)	2010 (Audited)
Sales of petroleum products:			
Hess	**$ 144,797**	$ 3,805,821	$ 4,307,112
PDVSA	**147,232**	3,937,571	4,254,761
Purchases of crude oil and products:			
Hess	**191,425**	709,570	607,040
PDVSA	**524,517**	6,412,491	6,214,869
Administrative service agreement fee paid to Hess	**4,286**	4,018	6,481
Bareboat charter of tugs and barges paid to HOVIC	**2,880**	2,873	3,161
Marine revenues received from PDVSA and Hess	**—**	567	911

5. Inventories

Inventories as of December 31 were as follows:

	2012 (Unaudited)	2011 (Audited)
Crude oil	**$ 52,878**	$ 183,345
Refined and other finished products	**92,154**	657,914
Less: LIFO adjustment	**(103,318)**	(734,177)
	41,714	107,082
Materials and supplies	**26,516**	52,512
Total	**$ 68,230**	$159,594

(Dollars in Thousands)

Table of Contents

During 2012 and 2011, reductions of inventory quantities resulted in a liquidation of LIFO inventories carried at below market costs, which improved operating results by approximately $745,000 and $270,000 respectively. During 2013, the Company intends to liquidate its remaining crude oil, refined and other finished products inventory.

6. Tax Exempt Revenue Bonds and Other Long-term Debt

Outstanding borrowings at December 31 consisted of the following:

	2012 (Unaudited)	2011 (Audited)
Tax-exempt revenue bonds (issued in 2002) at 6.50%	$ —	$126,753
Tax-exempt revenue bonds (issued in 2003) at 6.125%	—	74,175
Tax-exempt revenue bonds (issued in 2004) at 5.875%	—	50,660
Tax-exempt revenue bonds (issued in 2007) at 4.70%	—	104,095
Total tax exempt revenue bonds	$ —	$355,683

During 2012, the Company successfully tendered a cash offer for its $355,683 outstanding tax-exempt revenue bonds. The terms of the tender offer included a purchase price at par value, plus accrued but unpaid interest up to the purchase date, subject to the terms of the offering document.

HOVENSA had a 5-year $400,000 revolving credit facility until December 30, 2011, when it repaid outstanding borrowings and terminated the revolving credit facility. The agreement was collateralized by the physical assets and certain material contracts of the Company.

7. Environmental Matters

In 2011, the Company signed a Consent Decree with the U.S. Environmental Protection Agency (EPA) which among other things requires the Company to install equipment and implement additional operating procedures to reduce emissions over the next 10 years. The cost of installing this equipment would have been approximately $700,000. Since the refining facilities were shut down in 2012, with plans to subsequently operate as an oil storage terminal, the Company believes it will not be required to make material expenditures as outlined in the Consent Decree. Under the terms of the Consent Decree, the Company paid a penalty of $5,375 in 2011.

In the normal course of its business, the Company records liabilities for future environmental remediation expenditures when such environmental obligations are probable and reasonably estimable.

The Company is required to provide financial assurance to the EPA in connection with various forms of environmental compliance. The required financial assurance totaled approximately $41,000 at December 31, 2012 and $48,000 at December 31, 2011. This requirement was met by posting a letter of credit in 2012 and by passing a financial test in 2011.

8. Contingencies

The Company is subject to loss contingencies with respect to various lawsuits, claims and other proceedings, including environmental matters. A liability is recognized in the Company's financial statements when it is probable 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

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS – (Continued)
(Dollars in Thousands)

is not accrued; however, the Company discloses the nature of those contingencies. In management's opinion, based upon currently known facts and circumstances, the outcome of such loss contingencies will not have a material adverse effect on the Company's financial condition, results of operations and cash flows.

9. Retirement Plans

The Company has a funded non-contributory, defined benefit pension plan for substantially all of its employees. The plan provides defined benefits based on years of service and final average salary. At December 31, 2012 and 2011, the actuarial assumptions for the determination of the projected benefit obligation reflect the transition of the refinery to an oil storage terminal. The non-contributory defined benefit pension plan will remain in place and meet future obligations in accordance with terms of the plan, but terminated employees will no longer earn service toward future benefits.

The following table reconciles the projected benefit obligation and fair value of plan assets and shows the funded status of the pension plan:

	2012 (Unaudited)	2011 (Audited)
Reconciliation of projected benefit obligation:		
Benefit obligation at January 1	**$128,567**	$116,572
Service costs	**5,707**	9,243
Interest costs	**5,413**	6,373
Actuarial (gain) loss	**6,560**	(1,403)
Benefit payments	**(3,089)**	(2,218)
Projected benefit obligation at December 31	**143,158**	128,567
Reconciliation of fair value of plan assets:		
Fair value of plan assets at January 1	**84,751**	72,400
Actual return on plan assets	**9,480**	1,809
Employer contributions	**13,100**	12,760
Benefit payments	**(3,089)**	(2,218)
Fair value of plan assets at December 31	**104,242**	84,751
Funded status (plan assets less than benefit obligation)	**(38,916)**	(43,816)
Unrecognized net actuarial losses	**37,941**	36,367
Net amount recognized	**$ (975)**	$ (7,449)

The accumulated benefit obligation was $137,831 at December 31, 2012 and $124,769 at December 31, 2011.

Components of funded pension expense consisted of the following:

	2012 (Unaudited)	2011 (Audited)	2010 (Audited)
Service cost	**$ 5,707**	$ 9,243	$ 8,964
Interest cost	**5,413**	6,373	5,684
Expected return on plan assets	**(6,221)**	(5,427)	(4,095)
Amortization of unrecognized net actuarial losses	**1,727**	1,896	1,944
Net periodic benefit cost	**$ 6,626**	$12,085	$12,497

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS – (Continued)
(Dollars in Thousands)

The actuarial assumptions used in the Company's pension plan were as follows:

	2012 (Unaudited)	2011 (Audited)	2010 (Audited)
Assumptions used to determine benefit obligations at December 31:			
Discount rate	**4.0%**	4.4%	5.6%
Rate of compensation increase	**4.2%**	4.2%	4.2%
Assumptions used to determine net costs for years ended December 31:			
Discount rate	**4.4%**	5.6%	6.0%
Expected return on plan assets	**7.0%**	7.0%	7.0%
Rate of compensation increase	**4.2%**	4.2%	4.2%

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 investments that matches the maturity of the plan obligations. The overall expected return on plan assets is developed from the expected future returns for each asset category, weighted by the expected allocation of pension assets to that asset category. The Company engages an independent investment consultant to assist in the development of expected returns.

The Company's pension plan assets by category are as follows:

	2012 (Unaudited)	2011 (Audited)
Asset category		
Equity securities	**27%**	56%
Debt securities	**73**	44
Total	**100%**	100%

In order to reduce risk to the pension plan assets, target investment allocations were revised in 2012 to 73% debt securities and 27% equity securities. The target investment allocations for 2011 were 55% equity securities and 45% debt securities. Asset allocations are rebalanced on a regular basis throughout the year to bring assets to within a 2-3% range of target levels. Target allocations take into account analyses performed by the Company's pension consultant to optimize long-term risk/return relationships. All assets are highly liquid and may be readily adjusted to provide liquidity for current benefit payment requirements.

For purposes of valuing pension investments, a hierarchy for the inputs is used to measure fair value based on the source of the input, 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).

The following tables provide the fair value hierarchy of the financial assets of the qualified pension plan as of December 31, 2012 and 2011:

	Level 1	Level 2	Level 3
December 31, 2012 (Unaudited)			
Cash and short-term investment funds	**$ —**	**$ 144**	**$ —**
U.S. equities (domestic)	**22,934**	**—**	**—**
International equities (non-U.S.)	**5,537**	**—**	**—**
Fixed income	**75,627**	**—**	**—**
Total	**$ 104,098**	**$ 144**	**$ —**

Table of Contents

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS – (Continued)
(Dollars in Thousands)

	Level 1	Level 2	Level 3
December 31, 2011 (Audited)			
Cash and short-term investment funds	$ —	$ 329	$ —
U.S. equities (domestic)	38,872	—	—
International equities (non-U.S.)	8,338	—	—
Fixed income	37,212	—	—
Total	$ 84,422	$ 329	$ —

Cash and short-term investment funds consist of cash on hand, which is invested in a short-term investment fund that provides for daily investments and redemptions and is valued and carried at a $1 net asset value (NAV) per fund share.

Equities consist of registered mutual fund investments whose diversified holdings primarily include common stock securities issued by U.S. and non-U.S. corporations, respectively. Mutual fund shares are valued daily, with the NAV per fund share published at the close of each business day. These investments are classified as Level 1.

Fixed income securities consist of registered mutual fund investments whose diversified holdings primarily include U.S. Treasury securities, corporate bonds and mortgage backed securities.

HOVENSA has budgeted contributions of approximately $13,000 to its funded pension plan in 2013.

Estimated future pension benefit payments, which reflect expected future service, are as follows:

2013	$ 4,713
2014	4,816
2015	4,891
2016	4,956
2017	5,072
Years 2018 to 2022	27,174

The Company also maintains an unfunded post-retirement medical plan that provides health benefits to certain qualified retirees from ages 55 through 65. The projected benefit obligation for this plan was approximately $11,325 as of December 31, 2012 and $11,864 as of December 31, 2011. The decrease in the projected benefit obligation includes a change in actuarial assumptions to reflect the transition of the refinery to an oil storage terminal. This plan will also remain in place and meet future obligations in accordance with terms of the plan, but terminated employees will no longer earn service toward future benefits.

Table of Contents

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)	By-laws of Registrant incorporated by reference to Exhibit 3(1) of Form 8-K of Registrant dated February 2, 2011.
4(1)	Five-Year Credit Agreement dated as of April 14, 2011, 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 dated April 14, 2011.
4(2)	Indenture dated as of October 1, 1999 between Registrant and The Chase Manhattan Bank, as Trustee, incorporated by reference to Exhibit 4(1) of Form 10-Q of Registrant for the three months ended September 30, 1999.
4(3)	First Supplemental Indenture dated as of October 1, 1999 between Registrant and The Chase Manhattan Bank, as Trustee, relating to Registrant's 7 3/8% Notes due 2009 and 7 7/8% Notes due 2029, incorporated by reference to Exhibit 4(2) to Form 10-Q of Registrant for the three months ended September 30, 1999.
4(4)	Prospectus Supplement dated August 8, 2001 to Prospectus dated July 27, 2001 relating to Registrant's 5.30% Notes due 2004, 5.90% Notes due 2006, 6.65% Notes due 2011 and 7.30% Notes due 2031, incorporated by reference to Registrant's prospectus filed pursuant to Rule 424(b)(2) under the Securities Act of 1933 on August 9, 2001.
4(5)	Prospectus Supplement dated February 28, 2002 to Prospectus dated July 27, 2001 relating to Registrant's 7.125% Notes due 2033, incorporated by reference to Registrant's prospectus filed pursuant to Rule 424(b)(2) under the Securities Act of 1933 on March 1, 2002.
4(6)	Indenture dated as of March 1, 2006 between Registrant and The Bank of New York Mellon as successor to JP Morgan Chase, as Trustee, including form of Note. Incorporated by reference to Exhibit 4 to Registrant's Form S-3ASR filed with the Securities and Exchange Commission on March 1, 2006.
4(7)	Form of 2014 Note issued pursuant to Indenture, dated as of March 1, 2006, among Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase as Trustee. Incorporated by reference to Exhibit 4(1) to Registrant's Form 8-K filed with the Securities and Exchange Commission on February 4, 2009.
4(8)	Form of 2019 Note issued pursuant to Indenture, dated as of March 1, 2006, among Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase, as Trustee. Incorporated by reference to Exhibit 4(2) to Registrant's Form 8-K filed with the Securities and Exchange Commission on February 4, 2009.
4(9)	Form of 6.00% Note, incorporated by reference to Exhibit 4(1) to the Form 8-K of Registrant filed on December 15, 2009.
4(10)	Form of 5.60% Note incorporated by reference to Exhibit 4(1) to the Form 8-K of Registrant filed on August 12, 2010. 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 Commission a copy of any instruments defining the rights of holders of long-term debt of Registrant and its subsidiaries upon request.
10(1)	Extension and Amendment Agreement between the Government of the Virgin Islands and Hess Oil Virgin Islands Corp. incorporated by reference to Exhibit 10(4) of Form 10-Q of Registrant for the three months ended June 30, 1981.
10(2)	Restated Second Extension and Amendment Agreement dated July 27, 1990 between Hess Oil Virgin Islands Corp. and the Government of the Virgin Islands incorporated by reference to Exhibit 19 of Form 10-Q of Registrant for the three months ended September 30, 1990.
10(3)	Technical Clarifying Amendment dated as of November 17, 1993 to Restated Second Extension and Amendment Agreement between the Government of the Virgin Islands and Hess Oil Virgin Islands Corp. incorporated by reference to Exhibit 10(3) of Form 10-K of Registrant for the fiscal year ended December 31, 1993.
10(4)	Third Extension and Amendment Agreement dated April 15, 1998 and effective October 30, 1998 among Hess Oil Virgin Islands Corp., PDVSA V.I., Inc., HOVENSA L.L.C. and the Government of the Virgin Islands incorporated by reference to Exhibit 10(4) of Form 10-K of Registrant for the fiscal year ended December 31, 1998.

10(5)*	Incentive Cash Bonus Plan description incorporated by reference to Item 5.02 of Form 8-K of Registrant filed on March 13, 2012.
10(6)*	Financial Counseling Program description incorporated by reference to Exhibit 10(6) of Form 10-K of Registrant for fiscal year ended December 31, 2004.
10(7)*	Hess Corporation Savings and Stock Bonus Plan incorporated by reference to Exhibit 10(7) of Form 10-K of Registrant for fiscal year ended December 31, 2006.
10(8)*	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 the Registrant dated March 25, 2011.
10(9)*	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(10)*	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 fiscal year ended December 31, 2006.
10(11)*	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(12)*	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 fiscal year ended December 31, 2004.
10(13)*	2008 Long-term Incentive Plan, incorporated by reference to Annex B to Registrant's definitive proxy statement filed on March 27, 2008.
10(14)*	First Amendment dated March 3, 2010 and approved May 5, 2010 to Registrant's 2008 Long-term Incentive Plan, incorporated by reference to Annex B of Registrant's definitive proxy statement dated March 25, 2010.
10(15)*	Forms of Awards under Registrant's 2008 Long-term Incentive Plan incorporated by reference to Exhibit 10(14) of Registrant's Form 10-K for the fiscal year ended December 31, 2009.
10(16)*	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(17)*	Modified Form of Restricted Stock Award Agreement under Registrant's 2008 Long-term Incentive Plan incorporated by reference to Exhibit 10(3) of Form 8-K of Registrant filed on March 13, 2012.
10(18)*	Second Amendment dated March 23, 2012 and approved May 2, 2012 to Registrant's 2008 Long-term Incentive Plan, incorporated by reference to Annex A of Registrant's definitive proxy statement dated March 23, 2012.
10(19)*	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(20)*	Amended and Restated Change of Control Termination Benefits Agreement dated as of May 29, 2009 between Registrant and F. Borden Walker, 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(21)*	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 Registrant's Form 10-K 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 those referred to in Exhibit 10(17)).
10(22)*	Letter Agreement dated March 18, 2002 between Registrant and F. Borden Walker relating to Mr. Walker's participation in the Hess Corporation Pension Restoration Plan incorporated by reference to Exhibit 10(16) of Form 10-K of Registrant for the fiscal year ended December 31, 2001.
10(23)*	Agreement between Registrant and Gregory P. Hill relating to his compensation and other terms of employment, incorporated by reference to Item 5.02 of Form 8-K of Registrant filed January 7, 2009.
10(24)*	Agreement between Registrant and Timothy B. Goodell relating to his 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(25)*	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(26)	Asset Purchase and Contribution Agreement dated as of October 26, 1998, among PDVSA V.I., Inc., Hess Oil Virgin Islands Corp. and HOVENSA L.L.C. (including Glossary of definitions) incorporated by reference to Exhibit 2.1 of Form 8-K of Registrant filed on November 13, 1998.
10(27)	Amended and Restated Limited Liability Company Agreement of HOVENSA L.L.C. dated as of October 30, 1998 incorporated by reference to Exhibit 10.1 of Form 8-K of Registrant filed on November 13, 1998.
21	Subsidiaries of Registrant.
23(1)	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm, dated February 28, 2013, to the incorporation by reference in Registrant's Registration Statements (Form S-3 No. 333-179744, and Form S-8 Nos. 333-43569, 333-94851, 333-115844, 333-150992, 333-167076 and 333-181704), of its reports relating to Registrant's financial statements.
23(2)	Consent of DeGolyer and MacNaughton dated February 28, 2013.
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 January 31, 2013, on proved reserves audit as of December 31, 2012 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.*

Exhibit 21

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUBSIDIARIES OF THE REGISTRANT

Name of Company	Jurisdiction
Hess (Netherlands) Oil & Gas Holdings C.V.	The Netherlands
Hess (Netherlands) U.S. GOM Ventures B.V.	The Netherlands
Hess Capital Services Corporation	Delaware
Hess Capital Services L.L.C.	Delaware
Hess Energy Exploration Limited	Delaware
Hess Equatorial Guinea Inc.	Cayman Islands
Hess Exploration & Production Holdings Limited	Delaware
Hess Gulf of Mexico Ventures L.L.C.	Delaware
Hess International Holdings Corporation	Delaware
Hess International Holdings Limited	Cayman Islands
Hess International Petroleum, Inc.	Cayman Islands
Hess Libya (Waha) Limited	Cayman Islands
Hess Limited	United Kingdom
Hess Norge AS	Norway
Hess Oil and Gas Holdings Inc.	Cayman Islands
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-3 No. 333-179744) of Hess Corporation;

of our reports dated February 28, 2013, with respect to the consolidated financial statements and schedule of Hess Corporation and consolidated subsidiaries and the effectiveness of internal control over financial reporting of Hess Corporation and our report dated February 27, 2012 with respect to the financial statements of HOVENSA L.L.C., included in this Annual Report (Form 10-K) for the year ended December 31, 2012.

/s/ Ernst & Young, LLP
New York, New York
February 28, 2013

Exhibit 23(2)

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

February 28, 2013

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 January 31, 2013, containing our opinion on the proved reserves attributable to certain properties owned by Hess Corporation, as of December 31, 2012, (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, 2012. 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. 333-179744) and Form S-8 (No. 333-43569, No. 333-94851, No. 333-115844, No. 333-150992, No. 333-167076 and No. 333-181704).

Very truly yours,

/s/ DeGolyer and MacNaughton
DEGOLYER AND MACNAUGHTON

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
Chairman of the Board and
Chief Executive Officer

Date: February 28, 2013

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 28, 2013

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 ending December 31, 2012 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, John B. Hess, Chairman of the Board and 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
Chairman of the Board and
Chief Executive Officer

Date: February 28, 2013

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 ending December 31, 2012 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 28, 2013

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

January 31, 2013

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

Gentlemen:

Pursuant to your request, we have conducted a reserves audit of the net proved crude oil, condensate, natural gas liquids (NGL), and natural gas reserves, as of December 31, 2012, of certain selected properties of Hess Corporation (Hess) to determine the reasonableness of Hess' estimates. The audit was completed on January 31, 2013. Hess has represented to us that these properties account for approximately 76 percent on a net equivalent barrel basis of Hess' net proved reserves, as of December 31, 2012. We have reviewed information provided to us by Hess that it represents to be Hess' estimates of the net reserves, as of December 31, 2012, 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 of the United States Securities and Exchange Commission (SEC) and is to be used for inclusion in certain SEC filings by Hess.

Reserves 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, 2012. 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, except in Russia, where Hess owns 90 percent of a consolidated corporate joint venture. As a result, Hess net reserves include 10 percent of the Russian joint venture reserves not owned by Hess.

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 standard 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 natural 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, 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 2012 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, 2012, and which represent approximately 76 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, 2012			
	Oil and Condensate (MMbbl)	**Natural Gas Liquids (MMbbl)**	**Natural Gas (Bcf)**	**Oil Equivalent (MMboe)**
United States	297	53	252	392
Norway	260	23	218	319
Europe (excluding Norway and including Russia)	85	0	90	100
Africa	151	0	129	172
Asia	16	5	1,027	193
Total	**809**	**81**	**1,716**	**1,176**

Note: Gas is converted to oil equivalent using a 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 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 and 932-235-50-6 through 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 approximately 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, 2012, 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 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 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 as appropriate.

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.

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 $96.32 per barrel for West Texas Intermediate and $113.23 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 $102.25 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 $44.04 per barrel.

Natural Gas Prices

Hess has represented that the non-contracted natural 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 $2.851 per thousand cubic feet and the UK International Petroleum Exchange reference price was $9.526 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 $7.08 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, 2012, estimated oil and gas volumes.

DEGOLYER AND MACNAUGHTON

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/ James W. Hail, Jr., P.E.
James W. Hail, Jr., P.E.
President and Chief Executive Officer
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, James W. Hail, Jr., 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 the President of DeGolyer and MacNaughton, which company did prepare the letter report dated January 31, 2013 on the proved reserves audit of certain properties attributable to Hess Corporation, and that I, as President, was responsible for the preparation of this report.

2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Chemical Engineering in 1972; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers; the American Association of Petroleum Geologists; and the Society of Petroleum Evaluation Engineers and that I have in excess of 39 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ James W. Hail, Jr., P.E.

James W. Hail, Jr., P.E.
President and Chief Executive Officer
DeGolyer and MacNaughton