HESS CORP
Form 10-K
February 28, 2013
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)**
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 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	*(I.R.S. Employer*
incorporation or organization)	*Identification Number)*
1185 AVENUE OF THE AMERICAS,	**10036**
NEW YORK, N.Y.	*(Zip Code)*
(Address of principal executive offices)	

(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 þ No ¨

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

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

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

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

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

Large accelerated filer þ	Accelerated filer ¨	Non-accelerated filer ¨ (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 þ

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.

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Form 10-K

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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.

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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

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	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

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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.

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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.

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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.

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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.*

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(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

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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

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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.

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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.

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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,

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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.

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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,

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.

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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.

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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.

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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.

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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.

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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.*

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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.

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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.

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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

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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.

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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.

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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.

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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

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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 (In millions)	Total Used	Available Capacity
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

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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.

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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

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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

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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

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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.

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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.

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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 u 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.

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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.

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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.*

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Item 8. Financial Statements and Supplementary Data

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

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* *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.*

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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	By	/s/ John B. Hess
	John P. Rielly		John B. Hess
	Senior Vice President and		Chairman of the Board and
	Chief Financial Officer		Chief Executive Officer

February 28, 2013

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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

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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

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HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	December 31, 2012	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.

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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